

**LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF ENVIRONMENTAL SERVICES**

PUBLIC COMMENTS RESPONSE SUMMARY

**PART 70 OPERATING PERMIT 3086-V0
PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT PSD-LA-751**

PART 70 OPERATING PERMIT MODIFICATION 2560-00281-V1

**CONSOLIDATED ENVIRONMENTAL MANAGEMENT, INC.
NUCOR STEEL LOUISIANA
CONVENT, ST. JAMES PARISH, LOUISIANA
Agency Interest No. 157847**

This document responds to pertinent statements (questions and/or comments) received by mail, e-mail, and at the public hearing regarding the proposed permit actions. The following comments, together with the Louisiana Department of Environmental Quality (LDEQ) Office of Environmental Services' responses, are relevant to the initial Part 70 (Title V) Operating and Prevention of Significant Deterioration (PSD) permits for Consolidated Environmental Management, Inc. – Nucor Steel Louisiana's (Nucor's) Direct Reduced Iron (DRI) Plants, as well as to the modification of the Part 70 (Title V) Operating Permit for Nucor's currently permitted pig iron manufacturing facility. Comments provided in this document are taken verbatim from the hearing transcript and written submittals unless otherwise indicated.

A notice identifying a public hearing and requesting public comment on the proposed permits was published in *The Advocate*, Baton Rouge; and in *The Enterprise*, Vacherie, on November 24, 2010; in *The News-Examiner*, Convent, on November 25, 2010; and was mailed to the concerned citizens listed in the Office of Environmental Services (OES) Public Notice Mailing List on November 19, 2010. The LDEQ Office of Environmental Services held the public hearing on the proposed permits on December 28, 2010, at the St. James Parish Courthouse, Courtroom A, 5800 LA Highway 44, Convent, Louisiana.

The permit applications, proposed permits, Statements of Basis, and Environmental Assessment Statement were submitted to the St. James Parish Library, 1879 West Main Street, Litcher, Louisiana.

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I. Responses to Comments Submitted by Sierra Club Membership Services¹

Comment No. I.1

As a Louisianan, I ask that you reject Nucor's modified permit.² There are clear alternatives to coal for this project, and it is the duty of the Department of Environmental Quality to ensure the public health and environmental risk are not passed onto Louisiana residents at a time when there are better alternatives, both economically and environmentally.

The Nucor modified permit significantly increases emissions for ammonia and naphthalene, both known toxins. Nucor should submit an environmental assessment statement that reflects the entire facility both the pig iron plant and Direct Reduced Iron (DRI) facility -- and the increase in criteria pollutants and Toxic Air Pollutants (TAPs). Emissions of all pollutants -- including all New Source Review pollutants, hazardous air pollutants and toxic air pollutants -- should be quantified in good faith so that the public can review them during the permit process. The DEQ should not allow Nucor to wait until after beginning operations to quantify emissions. We cannot continue to put our communities at risk by building facilities that directly harm already impacted communities.

The wastewater permit Nucor obtained is specific to the pig iron plant, which is supposed to have zero discharge of process wastewater. However, Nucor is planning to construct the DRI plant first, and according to EPA, DRI plants discharge wastewater. The current Louisiana Pollution Discharge Elimination System permit -- which is based on outdated and therefore inaccurate assumptions -- should be terminated and Nucor should be required to submit an application based on the true discharges from the DRI plant.

Coal is the oldest and dirtiest form of power generation available today. There are more than 60 steel production facilities in 21 countries currently producing high purity iron products from natural gas, rather than coal. For example, the proposed DRI plant in Convent, which uses natural gas will emit only 1,100 tons per year of criteria pollutants, while the coal-burning pig iron plant permitted in May would emit 37,935 tons per year of criteria pollutants. The pig iron plant would also emit 107 tons per year of TAPs.

¹ EDMS Doc IDs (unless otherwise noted): 7774705, 7774707, 7774709, 7774711, 7774713, 7774715, 7774717, 7774719, 7774721, 7774723, 7774725, 7774727, 7774729, 7774731, 7774733, 7774735, 7774737, 7774739, 7774741, 7774743, 7774745, 7774747, 7774749, 7774751, 7774753, 7774755, 7774757, 7774759, 7774761, 7774763, 7774765, 7774767, 7774769, 7774771, 7774773, 7774775, 7774777, 7774779, 7774781, 7774783, 7774785, 7774787, 7774789, 7774791, 7774793, 7774795, 7774799, 7774801, 7774803, 7774807, 7774809, 7774811, 7774813, 7774815, 7774817, 7774819, 7774821, 7774823, 7774825, 7774827, 7774829, 7774831, 7774833, 7774835, 7774837, 7774839, 7774841, 7774843, 7774845, 7774847, 7774849, 7774851, 7774853, 7774855, 7774857, 7774859, 7774861, 7774863, 7774865, 7774867, 7774869, 7774871, 7774873, 7774875, 7774877, 7774879, 7774881, 7774883, 7774885, 7774887, 7774889, 7774891, 7774893, 7774895, 7774897, 7774899, 7774901, 7774903, 7774905, 7774907, 7774909, 7774911, 7774913, 7774915, 7774917, 7775035, 7775037, 7775039, 7775041, 7775043, 7778044, 7781888, 7781890 (pp. 6 – 7), 7781894, 7781896, 7781898, 7781900, 7781902, 7788813, 7788815, & 7788817

² One comment begins with the phrase “As a Human Being who Breathes ...” (EDMS Doc ID 7788817); another begins with “As a Louisianan and a resident of the Donaldsonville community less than 15 miles from the proposed Nucor plant ...” (EDMS Doc ID 7774827); a third “As a citizen of Louisianan [*sic*], I ask that you reject Nucor's modified air permit for their pig iron plant” (EDMS Doc ID 7774817).

Steel facilities using alternative energy sources like natural gas do not have the same public health and environmental risks as the same size facilities using coal. We can promote for jobs for Louisianans, and create jobs in a clean, environmentally responsible way. The DRI facility should have better safeguards, and I advise DEQ to reject Nucor's proposed air permit until advanced protections are put in place. Reject Nucor Steel's modified pig iron air permit and end Louisiana's dependence on a nineteenth-century technology.

I will not repeat what others have posted through this Sierra Club site; I am sure that by now you know all the arguments for and against Nucor. I will, as a native Louisianan, ask that you reject Nucor's modified air permit for their pig iron plant. Louisiana's air, our beautiful land, our reputation is already soiled enough. Let's turn it around in the future.³

Please understand that we are in support of the Nucor facility and know the economic benefits it can bring to the region. We want to support the project but can only do so if they process in a responsible way that takes public health and environmental concerns into account.⁴

When making your decisions regarding Nucor's permits, please consider how you would feel if you were raising young children within 15 miles of the plant.⁵

As a North Louisianan I cannot help but note that our state has an opportunity to provide synergistic economic stimulation. North Louisiana is currently in a natural gas drilling boon. If this plant were powered by gas from Louisiana the entire state would benefit. It is no secret that north of I-10 the state is industrially stagnate. We have a rare opportunity to benefit our state economy economically and environmentally, let us not squander it.⁶

TRuly [*sic*], we have suffered enough with Hurricane Katrina and the Deep water oil spill damaging our environment as well as our lives and spirits. Spewing out more toxins every years [*sic*] from dirty coal is simply not allowable. As the 'bottom' end of the Mississippi river [*sic*], we get all the effluent and waste disposed into the river along its journey across the country, and we drink this water. The toxic load to Southeastern Louisiana is past healthy human exposure. We are the source of natural gas, why is this not considered the power to run this new plant?⁷

Is Louisiana concerned about the health of its citizens? Why not invest in alternative energy technology tailor-made for our state, like solar panels and hot water heaters, like wind turbines, like electricity from wave-driven action in the Gulf, like biomass from farm waste, like recycled waste from garbage?⁸

My sister lived in Baton Rouge for 30 years and died last year with an aggressive very horrible cancer. Many many residents of Baton Rouge end up with all kinds of cancer. Pollution and air quality in southern Louisiana is already a problem.⁹

³ EDMS Doc ID 7774805

⁴ EDMS Doc ID 7774827

⁵ *Ibid.*

⁶ EDMS Doc ID 7774769

⁷ EDMS Doc ID 7774745

⁸ EDMS Doc ID 7774763

⁹ EDMS Doc ID 7774883

This state already has far too many pollutants in the air and water; we do not need more!¹⁰

I am also worried that the jobs will be going to out of state workers and the state will loose [sic] again in both economic and environmental issues.¹¹

I understand that the Nucor modified permit uses coal as an energy source, and that the permit will allow Nucor to inject significantly increased emissions for ammonia and naphthalene, both of which are known toxins.¹²

There are clear alternatives to coal for this project, and it is the duty of the Department of Environmental Quality to ensure that public health and environmental risks are minimized, not rubber stamped in any efforts to create jobs. This plant should proceed, but only if it can do so without trashing Louisiana's environment. We have allowed far too much damage to our coast, our communities and our environment by letting industrial corporations run rampant without requiring common-sense steps to protect our future. I hope we have finally learned from our history, but in the rush to provide Nucor with permit, it seems like we have not.¹³

LDEQ Response to Comment No. I.1

The proposed modification to Permit No. 2560-00281-V0, issued May 24, 2010, is not intended to “reauthorize” construction of the pig iron manufacturing facility. Permit Nos. 2560-00281-V0 and PSD-LA-740 remain effective until modified and authorize Nucor to construct and operate the emissions units described therein, subject to the prescribed emissions limitations, monitoring requirements, and other conditions.

As detailed in the Basis for Decision associated with the initial Title V and Prevention of Significant Deterioration (PSD) permits for the site, LDEQ has already determined that the pig iron manufacturing facility, as originally permitted, “will not cause air quality impacts that will adversely affect human health or the environment in St. James Parish or in the surrounding parishes.” Further, LDEQ concluded that permits “minimized or avoided potential and real adverse environmental impacts to the maximum extent possible and that social and economic benefits of the proposed Nucor facility outweigh adverse environmental impacts.”¹⁴

Denial of the proposed modification to Permit No. 2560-00281-V0 would leave that permit in place and effective. Other the other hand, approval of this permit action will result in substantial reductions in emissions of criteria pollutants compared to the V0 permit. Changes in the pig iron manufacturing facility's permitted emissions, in tons per year (TPY), are as follows:

<u>Pollutant</u>	<u>Before</u>	<u>After</u>	<u>Change</u>
PM ₁₀	681.05	467.39	-213.66
SO ₂	3781.87	2936.86	-845.01
NO _x	3791.83	457.16	-3334.67

¹⁰ EDMS Doc ID 7774731

¹¹ EDMS Doc ID 7774779

¹² EDMS Doc ID 7774817

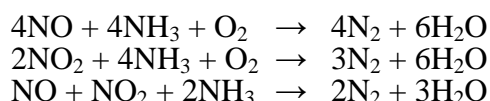
¹³ EDMS Doc ID 7775043

¹⁴ EDMS Doc ID 2947527 (pp. 1 – 32)

CO	29,394.48	28,395.47	-999.01
VOC	265.22	206.72	-58.50

LDEQ has reviewed the Environmental Assessment Statements (EAS) submitted as part of the application for the initial permits for the pig iron manufacturing facility and with the application for the DRI plants. LDEQ has performed the necessary analysis and balancing as required by the “IT decision” and its progeny on *both* projects. Even if an EAS that addresses both the pig iron manufacturing facility and the DRI plants was required, the ensuing “IT Analysis” by LDEQ would simply reflect the separate analyses performed for the individual projects. This is acceptable, particularly since the projects are “independent” as discussed elsewhere in this Public Comments Response Summary.

As noted in the proposed permit, the ammonia (NH₃) increase results solely from the installation of NO_x control technology (i.e., selective catalytic reduction, or SCR). SCR systems selectively reduce NO_x emissions by injecting NH₃ into the exhaust gas stream upstream of a catalyst. NO_x, NH₃, and O₂ react on the surface of the catalyst to form N₂ and H₂O. The chemical equation for the stoichiometric reaction using either anhydrous or aqueous ammonia is:



The permit modification will **not** increase permitted emissions of naphthalene. In fact, permitted emissions of naphthalene (and methylnaphthalenes) will decrease by 0.01 TPY due to elimination of the coke battery HRSG bypass vents.

In the “Emission Rates for TAP/HAP & Other Pollutants” section of Permit No. 2560-00281-V0, annual emission limits were established for naphthalene¹⁵ and “naphthalene (and methyl naphthalenes).”¹⁶ However, the Air Permit Briefing Sheet of Permit No. 2560-00281-V0 reflected only total naphthalene emissions.

The compounds regulated as toxic air pollutants (TAPs) under LAC 33:III.Chapter 51 include naphthalene (CAS No. 91-20-3), methylnaphthalene (CAS No. 1321-94-4), 1-methylnaphthalene (CAS No. 90-12-0), and 2-methylnaphthalene (CAS No. 91-57-6) and are collectively referred to as “naphthalene (and methylnaphthalenes)” in Tables 51.1 and 51.2 of LAC 33:III.5112. Because Permit No. 2560-00281-V1 correctly represents the regulated TAP as naphthalene (and methylnaphthalenes), “Before” emissions should be listed as 2.47 TPY. Permit No. 2560-00281-V1 will be revised accordingly.

The permits establish emission limitations for all regulated NSR pollutants, hazardous air pollutants, and toxic air pollutants anticipated to be emitted from the pig iron manufacturing facility and DRI plants. The purpose of stack testing is to verify compliance with permit limits, not to “quantify” emissions once operations begin.

With respect to the water discharges from the DRI plants, Nucor will be a net water user and will not discharge wastewater under normal conditions.¹⁷ Any discharges to waters of the State will be regulated under a Louisiana Pollutant Discharge Elimination System (LPDES) permit. The

¹⁵ EQT 0001, EQT 0007, GRP 0001, GRP 0002, RLP 0006, and RLP 0012

¹⁶ EQT 0002 and EQT 0008

¹⁷ IT Questions Response, Section 7.2.3.2 (EDMS Doc ID 7731649)

“outdated” assumptions upon which the commenters claim Nucor’s current LPDES permit is based are not further explained.

The comment concerning the effluent and waste disposed into the Mississippi River “along its journey across the country” is not relevant to the current permitting action. Nevertheless, there are programs in place designed to reduce the discharges to the Mississippi River. Any discharges to the Mississippi River from the facility will comply with all applicable water quality standards, which consider the Mississippi River’s classification as a source of drinking water.

The commenters note that “coal is the oldest and dirtiest form of power generation available today” and suggest alternative energy technology. At the pig iron manufacturing facility, coal is a raw material for the iron-making process and is not used to generate electricity. Coal, after subjection to the coking process, is used as a reductant in the blast furnace, chemically transforming the iron oxides contained within iron ore into elemental iron.

In typical coal combustion, the intent of the process is to join all atoms of carbon in the coal with atoms of oxygen, in order to form carbon dioxide (CO₂). The heat of this reaction is captured and converted to electrical energy. After combustion, the ash residue of the coal may become airborne in the flue gas (fly ash) or remain in the combustion unit to be reclaimed and disposed of (bottom ash). Additionally, nearly all of the sulfur with the coal fuel is oxidized, primarily forming SO₂.

In the coking process, coal is subjected to high heat in a battery of ovens, with the object of thermally cracking the organic compounds in the coal, leaving only pure carbon and simple carbon compounds, along with nearly all of the ash, in the resulting coke. After coking is completed, approximately two thirds of the coal’s originally carbon content remains in the coke, and more than 60% of the original sulfur. The finished coke is then transported to the blast furnace for use as a reductant.

During the coking process, the volatile fractions of the coal are liberated and are collectively known as coke oven gas. The gas is ducted from the oven chamber into the refractory oven walls and sole flues beneath the chamber, where combustion of the gas is completed. The coke oven gas is combusted in order to provide heat to perpetuate the coking process and to destroy organic pollutants in the gas. By utilizing the energy of the coke oven gas, supplemental fuels such as natural gas are not needed. Remaining heat energy from the coke oven flue gas, sometimes referred to as “waste heat,” is collected and converted into steam energy in order to make the process as efficient as possible. The resulting steam may be used for plant needs or power generation.

Commenters suggest that steel facilities “using alternative energy sources like natural gas” are preferable from an environmental standpoint to those employing coal. While potential emissions from the proposed DRI plants are less than those associated with the pig iron manufacturing facility, direct reduced iron, or sponge iron, cannot be used to make the full range of steel products manufactured by Nucor at its other operating locations due to the fact that insufficient carbon is retained in the iron produced by the DRI process. Thus, the need for the pig iron manufacturing facility remains.¹⁸ Alternative energy sources, such as solar panels, hot water heaters, wind turbines, etc. are not relevant to the current permitting actions.

Regarding the statement that the “DRI facility should have better safeguards” and the suggestion that LDEQ should “reject Nucor’s proposed air permit until advanced protections are put in place,”

¹⁸ See Section IV.B of LDEQ’s Basis for Decision associated with Permit No. 2560-00281-V0 (EDMS Doc ID 2947527, pp. 9 – 11).

it is not clear to what “safeguards” or “advanced protections” the commenters are referring. The permits for the DRI plants will require that emissions be controlled to meet or exceed the requirements of all applicable regulations.

Regarding Louisiana’s air quality, the Clean Air Act required the EPA to establish health-based National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. The Act established two types of national air quality standards. *Primary* standards are set to protect public health, including the health of “sensitive” populations such as asthmatics, children, and the elderly. *Secondary* standards are set to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. According to EPA, air quality that adheres to such standards is protective of public health, animals, soils, and vegetation. All areas of the state are in compliance with these federal air quality standards.

In addition, LDEQ has promulgated risk-based ambient air standards (AAS) for the toxic air pollutants regulated under LAC 33:III.Chapter 51. TAP emissions from Nucor will be compliant with these AAS.

The issue of economic benefits in the form of jobs associated with the proposed project is addressed in Section IV.E.2 of LDEQ’s Basis for Decision for Permit No. 2560-00281-V1.

II. Responses to Comments Submitted by the Tulane Environmental Law Clinic dated January 3, 2010¹⁹

Comment No. II.1

THE PROPOSED TITLE V PERMIT FOR PIG IRON MANUFACTURING FAILS TO APPLY MACT STANDARDS FOR THE TOPGAS BOILERS.

As LDEQ acknowledges, the Nucor complex is a “major source” of hazardous air pollutants under § 112 of the Clean Air Act. The proposed Title V/Pig Iron permit, however, violates Clean Air Act § 112(j) by failing to incorporate case-by-case MACT standards for the facility’s four topgas boilers. *See* 42 U.S.C. § 7412(j)(5) (the “permit ... shall contain emission limitations for the hazardous air pollutants subject to regulation under this section and emitted by the source that the Administrator (or the State) determines, on a case by-case basis, to be equivalent to the limitation that would apply [if EPA had timely promulgated a standard].”). The proposed Title V/Pig Iron permit is also invalid because it fails to “include enforceable emission limitations and standards ... as are necessary to assure compliance with applicable requirements of this Act” because it does not contain emissions limits consistent with § 112(j)(5). 42 U.S.C. § 7661c (mandating conditions for Title V permits). Moreover, construction of the facility would be illegal under Clean Air Act § 112(g)(2), 42 U.S.C. § 7412(g)(2). *See Sierra Club, Inc. v. Sandy Creek Energy Associates*,--- F.3d ----, 2010 WL 4725044 (5th Cir. 2010) (finding construction of a coal-fired electric generating plant that failed to receive a final MACT determination for its boiler in violation of § 112(g) of the Clean Air Act).

As background, the Clean Air Act requires EPA to identify categories of sources that emit listed hazardous air pollutants and develop national standards that restrict emissions

¹⁹ EDMS Doc ID 7781475

to a level consistent with MACT standards for each source category. *See* CAA § 112(c)-(e), 42 U.S.C. § 7412(c)-(e). The category of industrial boilers is defined as “a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.” 40 C.F.R. 63.7575 (2009). Nucor’s four topgas boilers (PWR-101 - PWR-104; EQT 23-26) fit within this definition of industrial boilers.

EPA was required under the Clean Air Act to set MACT standards for all major industry source categories by November 15, 2000. Though EPA missed its deadline for the industrial boiler source category, it did publish MACT emissions limitations for this source category in September 2004. But on June 8, 2007, the U. S. Court of Appeals for the D.C. Circuit vacated that rule. Because the D.C. Circuit vacated the emissions limitations for industrial boilers, there are currently no source-specific emissions limitations for industrial boilers. The vacature, thus, triggered the “MACT hammer,” requiring Nucor to obtain MACT limits for its topgas boilers from LDEQ on a case-by-case basis. *See* CAA § 112(j), 42 U.S.C. § 7412(j) (a stop-gap measure requiring major sources to obtain a “case-by-case” MACT determination from EPA or state regulators if the source falls into a category for which EPA has missed its deadline to promulgate a source-wide MACT rule).

The Fifth Circuit recently ruled on the implications of § 112(g) when a court vacates an air standard. *Sierra Club, Inc. v. Sandy Creek Energy Associates*, --- F.3d ---, 2010 WL 4725044 (5th Cir. 2010). In *Sandy Creek*, the Court found that construction of a coal-fired electric generating plant that failed to receive a final MACT determination for its boiler violates § 112(g) of the Clean Air Act even though the facility received its permit at a time when an EPA rule purported to exempt electric generating units from MACT requirements. *See id.* at 3-6. Because a D.C. Circuit later vacated EPA’s rule to exempt such units from MACT, the Fifth Circuit held that the “ongoing construction of a coal fired power plant—for which no MACT determination has been made—is in violation of § 112(g)(2)(B).” *Id.* at 4. The Fifth Circuit said: “As a result of the D.C. Circuit’s decision in *New Jersey*, § 112(g)’s construction prohibition on ‘major sources’ with no MACT determination once again became applicable to all coal-fired power plants.” *Id.* at 2.

Consistent with *Sandy Creek*, Nucor must obtain a case-by-case MACT determination for its topgas boilers because the D.C. Circuit Court’s decision eliminated EPA’s earlier boiler MACT standard.

LDEQ Response to Comment No. II.1

Section 112(g) of the Clean Air Act (CAA) does not apply to the pig iron manufacturing facility; thus, the *Sandy Creek* decision is not relevant to the matter at hand.

Per 40 CFR 63.40(a), the “requirements of §§63.40 through 63.44 of [Subpart B] carry out section 112(g)(2)(B) of the 1990 Amendments.” 40 CFR 63.40(b) states:

Overall requirements. The requirements of §§63.40 through 63.44 of this subpart apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants after the effective date of section 112(g)(2)(B) (as defined in §63.41) and the effective date of a title V permit program in the State or local jurisdiction in which the major source is (or would be) located **unless the major source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to section 112(d), section 112(h),**

or section 112(j) and incorporated in another subpart of part 63, or the owner or operator of such major source has received all necessary air quality permits for such construction or reconstruction project before the effective date of section 112(g)(2)(B).

(Emphasis added.)

In the instant case, the “major source in question has been specifically regulated ... under a standard issued pursuant to section 112(d).” The pig iron manufacturing facility is subject to the following MACT standards “incorporated in another subpart of part 63”:

- 40 CFR 63 Subpart L – National Emission Standards for Coke Oven Batteries;
- 40 CFR 63 Subpart CCCCC – National Emission Standards for Hazardous Air Pollutants for Coke Ovens: Pushing, Quenching, and Battery Stacks; and
- 40 CFR 63 Subpart FFFFF – National Emission Standards for Hazardous Air Pollutants for Integrated Iron and Steel Manufacturing Facilities

Turning to section 112(j) of the CAA, 40 CFR 63.50(a) states that the “requirements of this section [§63.50] through §63.56 implement section 112(j) of the Clean Air Act (as amended in 1990).”

40 CFR 63.52 establishes the approval process for new and existing affected sources. Neither 40 CFR 63.52(a) nor 40 CFR 63.52(c) is applicable. The topgas boilers were not subject to section 112(j) as of the section 112(j) deadline (they have not been constructed), nor does Nucor have a permit addressing section 112(j) requirements. Further, 40 CFR 63.54 is applicable only to an “owner or operator who constructs a new affected source subject to §63.52(c)(1).”

40 CFR 63.52(b) is controlling in this instance. This paragraph applies to sources that become subject to section 112(j) after the section 112(j) deadline and that do not have a Title V permit addressing section 112(j) requirements. 40 CFR 63.52(b)(1) reads, in pertinent part:

When one or more sources in a category or subcategory subject to the requirements of this subpart are installed at a major source, or result in the source becoming a major source due to the installation, and the installation does not invoke section 112(g) requirements, the owner or operator must submit an application meeting the requirements of §63.53(a) **within 30 days of startup of the source.**

(Emphasis added.)

Therefore, the suggestion that a case-by-case MACT determination must be included in the initial Title V permit is unsupported by and contrary to implementing federal regulations.

The topgas boilers are fueled by clean burning gaseous fuels – natural gas and blast furnace gas, which is composed of nitrogen, carbon dioxide, carbon monoxide, and water vapor, and hydrogen. HAP emissions from these boilers are *negligible*.

In fact, neither the original “National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters” (i.e., 40 CFR 63 Subpart DDDDD), promulgated by EPA on September 13, 2004,²⁰ nor EPA’s proposed “National Emission

²⁰ 69 FR 55253. Subpart DDDDD was subsequently vacated and remanded to EPA by the U.S. Court of Appeals for the District of Columbia Circuit on June 19, 2007.

Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters”²¹ establish emission limits for natural gas and blast furnace gas-fired boilers and process heaters. In view of EPA’s findings as published in these two rulemakings, the topgas boilers are already controlled to MACT standards.

On December 7, 2010, EPA filed a motion requesting that the D.C. Circuit extend the agency’s court-ordered deadline to promulgate MACT standards. According to this document, “the public interest will be best served if the Agency’s deadline ... is extended from January 16, 2011, to April 13, 2012, so that EPA can re-propose the rules for further public comment to ensure that the final rules are logical outgrowths of the proposals.” On January 21, 2011, the court denied this motion and directed EPA to promulgate final rules by February 21, 2011.

Because a federal standard will be in place before operations of the topgas boilers commence, note that 40 CFR 63.50(c) specifies that:

Once a generally applicable Federal standard governing that source has been promulgated, the owner or operator of the affected source and the permitting authority are not required to take any further actions to develop an equivalent emission limitation under section 112(j) of the Act.

Thus, section 112(j) of the CAA does not apply.

Comment No. II.2

LDEQ MUST REJECT THE PROPOSED PERMITS AND REQUIRE NUCOR TO SUBMIT A PSD APPLICATION THAT COVERS GREENHOUSE GAS EMISSIONS FOR THE ENTIRE FACILITY.

LDEQ must permit the pig iron and DRI processing units under a single PSD permit consistent with Clean Air Act’s PSD requirements. 42 U.S.C. §§ 7470-7477, 40 C.F.R. §§ 51.165 & 52.21 and La. Admin. Code tit. 33 pt. III § 509. By permitting Nucor’s DRI and pig iron units separately, LDEQ has deprived the public the opportunity to review and comment on the aggregate emissions and air quality impacts from the whole plant. And by piecemealing the permits, LDEQ has failed to require PSD review for greenhouse gases (GHG) for the entire plant.

LDEQ did not provide any discussion of GHG emissions from the pig iron plant in the proposed permits for the DRI facility, and the previously issued permit for the pig iron plant did not include a BACT analysis or BACT limits for GHG emissions. Thus, LDEQ did not evaluate the aggregate emissions from both the pig iron and DRI processing units, nor did it develop and implement BACT limits for the pig iron plant.

Moreover, energy requirements for pig iron production have been estimated at 12.2 MMBtu/tonne (13.5 MMBtu/ton) of liquid pig iron and 10.4 MMBtu/tonne (11.5 MMBtu/ton) for pig iron nuggets depending upon ore type, reformer, etc. Considering the substantially higher energy requirements compared to DRI production, LDEQ must evaluate substituting the pig iron portion of the facility with DRI production as an alternative control option for iron feed stock production.

²¹ 75 FR 32006 (June 4, 2010)

LDEQ Response to Comment No. II.2

Regarding the need to address the pig iron manufacturing facility and DRI plants under a single Prevention of Significant Deterioration (PSD) permit, see LDEQ Response to Comment No. V.A.2.

The PSD permit for the pig iron manufacturing facility, PSD-LA-740, issued May 24, 2010, does not establish limitations for greenhouse gas emissions. However, according to EPA’s final “Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule”.²²

A major source that obtains a PSD permit prior to January 2, 2011 will not be required under EPA regulations to reopen or revise the PSD permit to address GHGs in order for such a source to begin or continue construction authorized under the permit.²³

Furthermore, a source that is authorized to construct under a PSD permit but has not yet begun actual construction on January 2, 2011 may still begin actual construction after that date without having to amend the previously-issued PSD permit to incorporate GHG requirements.²⁴

Regarding the need to evaluate “substituting the pig iron portion of the facility with DRI,” direct reduced iron, or sponge iron, cannot be used to make the full range of steel products manufactured by Nucor at its other operating locations due to the fact that insufficient carbon is retained in the iron produced by the DRI process. Thus, the need for the pig iron manufacturing facility remains.²⁵

Comment No. II.3

LDEQ HAS THE CONSTITUTIONAL DUTY AS PUBLIC TRUSTEE TO CONSIDER BENZENE EMISSIONS AND MERCURY EMISSIONS FROM THE PIG IRON PROCESSING UNITS.

Comment No. II.3.A

A. LDEQ’s Constitutional Duty Under Art. IX Section 1 of the Louisiana Constitution.

The Louisiana Constitution mandates that “[t]he natural resources of the state, including air and water, and the healthful, scenic, historic, and esthetic quality of the environment shall be protected, conserved and replenished insofar as possible and consistent with the health, safety, and welfare of the people.” According to state statute, LDEQ is the public trustee with the duty to protect Louisiana’s air.

As the Louisiana Supreme Court pointed out in a landmark environmental decision, LDEQ’s “role as the representative of the public interest does not permit it to act as an umpire passively calling balls and strikes for adversaries appearing before it; the rights of the public must receive active and affirmative protection at the hands of the

²² 75 FR 31514 (June 3, 2010)

²³ 75 FR 31593

²⁴ *Ibid.*

²⁵ See Section IV.B of LDEQ’s Basis for Decision associated with Permit No. 2560-00281-V0 (EDMS Doc ID 2947527, pp. 9 – 11).

[department].” *Save Ourselves, Inc. v. La. Env’tl. Control Com’n*, 452 So.2d 1152, 1157 (La. 1984). Indeed, LDEQ has the affirmative duty to analyze the pig iron plant, including the effects of its carbon dioxide and other greenhouse gas emissions to determine whether:

Potential and real adverse environmental effects of the proposed project have been avoided to the maximum extent possible;

A cost benefit analysis of the environment impact costs balanced against the social and economic benefits of the project demonstrate that the latter outweighs the former; and

There are alternative projects or alternative sites or mitigating measures which would offer more protection to the environment than the proposed project without unduly curtailing non-environmental benefits to the extent applicable.

In re Rubicon, Inc., 95-0108 (La. App. 1 Cir. 2/14/96) 670 So. 2d 475, 483 (articulating the holding in *Save Ourselves, Inc.* as the above three-part test).

LDEQ Response to Comment No. II.3.A

LDEQ considered greenhouse gas (GHG) emissions from the pig iron manufacturing facility prior to the issuance of Permit Nos. 2560-00281-V0 and PSD-LA-740. See Section IV.D.1.e of the Basis for Decision associated with the initial permits for the site.²⁶ Further, Permit No. 2560-00281-V1 results in a significant decrease in potential GHG emissions.

Comment No. II.3.B

B. LDEQ’s Constitutional Duty As Public Trustee Requires It To Consider the Plant’s Mercury Emissions.

The draft Title V/Pig Iron permit would allow 0.24 tons/year of mercury emissions for the pig iron processing unit. Mercury is an extremely hazardous neurotoxin that is dangerous at very low levels. Mercury emitted from coal plants becomes methylmercury in the environment, where it becomes toxic in even minute amounts. Readily absorbed by living tissues, methylmercury can cause serious birth defects, central nervous system and brain damage, diminished intelligence, and, recent evidence suggests, autism. According to the FDA standard, it would only take one pound of methylmercury to contaminate 500,000 pounds of fish, which, when consumed by humans and wildlife, increases their mercury levels. EPA has found that 1 in 6 women has levels of mercury in her blood above the safe standard, putting her future children at risk for learning and behavioral problems associated with mercury poisoning.

Mercury emissions are a special concern here since Nucor plans to build the pig iron plant just south of the Maurepas Marsh—the soils of which are likely to be the most heavily impacted by wet and dry mercury deposition from the pig iron plant. Mercury deposition to the slack marsh water and sediments adjacent to this mercury source can contaminate fish and shellfish contamination in these adjacent wetland areas.

²⁶ EDMS Doc ID 2947527 (pp. 23 – 24)

The Maurepas Marsh contains segments of the Blind River and Amite River, which the state already lists for mercury water quality impairment under Section 303(d) of the Clean Water Act. Furthermore, portions of the Bogue Falaya River, Tchefuncte River, Tangipahoa River, bayou [*sic*] Liberty, Blind River, Bogue Chitto River and Pearl River and these waters plus others are on mercury advisory lists with the following warning:

Women of childbearing age and children less than seven years of age SHOULD NOT CONSUME largemouth bass and crappie and should consume no more than ONE MEAL PER MONTH of freshwater drum, spotted bass, or catfish combined from the advisory area. Other adults and children seven years of age and older should consume no more than TWO MEALS PER MONTH of largemouth bass and crappie and no more than FOUR MEALS PER MONTH of freshwater drum, spotted bass, or catfish combined from the advisory area. Unless the fish species is specifically addressed in the details of the advisory, please limit consumption of all species in an advisory area to FOUR MEALS PER MONTH.

Because of the potential adverse environmental and health impacts associated with the mercury emissions from pig iron processing, LDEQ must analyze these impacts consistent with its constitutional duty.

LDEQ Response to Comment No. II.3.B

LDEQ has considered Nucor's mercury emissions. Mercury in the air is a global problem. Recent estimates of annual total global mercury emissions from all sources -- both natural and human-generated -- range from roughly 4400 to 7500 tons per year. Human-caused U.S. mercury emissions are estimated to account for roughly 3 percent of the global total. Because mercury can be transported thousands of miles in the atmosphere, and because many types of fish are caught and sold globally, effective exposure reduction will require reductions in global emissions.²⁷

Louisiana has established health-based Ambient Air Standards (AAS) for a group of compounds known as Toxic Air Pollutants (TAPs). TAPs include the federally-regulated Hazardous Air Pollutants (HAPs), including mercury, as well as a handful of other compounds such as ammonia and hydrogen sulfide. The impact of mercury emissions will be below its AAS established by LAC 33:III.Chapter 51.

EFFECTS ON AMBIENT AIR

Pollutant	Time Period	Calculated Maximum Ground Level Conc.	AAS
mercury	8 hr. avg.	0.00322 µg/m ³	1.19 µg/m ³

With Permit No. 2560-00281-V0, LDEQ required mercury controls above and beyond those required by applicable federal and state regulations. For the Coke Battery 1 Flue Gas Desulfurization Stack (COK-111, RLP 0006) and the Coke Battery 2 Flue Gas Desulfurization Stack (COK-211, RLP 0012), Nucor must inject activated carbon at a rate of 2 pounds carbon per 1 million actual cubic feet of coke oven flue gas. The efficiency of the activated carbon and flue gas desulfurization systems (as a whole) will be determined during the requisite performance test. The injection rate of activated carbon may be revisited at that time, and permitted rates will be adjusted accordingly.

²⁷ <http://www.epa.gov/air/mercuryrule/factsheetfin.htm>

Comment No. II.3.C

C. LDEQ Must Consider the Impacts of Benzene Emissions from Pig Iron Processing.

The proposed Title V permit for the pig iron processing unit allows Nucor to emit 56.04 tons per year of benzene, which is a known carcinogen. This is an extraordinarily high permit limit for benzene. Consistent with its public trustee duty, LDEQ must consider the impacts of the plant's benzene emissions on health and the environment. LDEQ must explain in detail whether there are alternatives or mitigating measures which would offer more protection to health and the environment, such as DRI processing as a total substitute for pig iron processing for the manufacturing of iron feed stock.

LDEQ Response to Comment No. II.3.C

LDEQ has considered Nucor's benzene emissions. As explained in LDEQ Response to Comment No. II.3.B, Louisiana has established health-based AAS for TAPs. The impact of benzene emissions will be below its AAS established by LAC 33:III.Chapter 51.

EFFECTS ON AMBIENT AIR

Pollutant	Time Period	Calculated Maximum Ground Level Conc.	AAS
benzene	Annual	0.54 $\mu\text{g}/\text{m}^3$	12.00 $\mu\text{g}/\text{m}^3$

The benzene AAS is based on an annual average. An annual AAS is based on either an EPA-verified inhalation unit risk factor (URF) for cancer risk level of 1 in 10,000 or a noncarcinogenic inhalation Reference Concentration (RfC). The URF is established by a quantitative risk assessment performed by EPA and is an estimate of the probability of developing cancer due to continuous exposure to a concentration of 1 $\mu\text{g}/\text{m}^3$ of the pollutant in question over a 70 year period. The RfC represents an estimate of the daily exposure that is likely to be without an appreciable risk of deleterious effects during a person's lifetime. The RfC is based on a continuous inhalation exposure and considers toxic effects for both the respiratory system and effects peripheral to the respiratory system. Both the URF and RfC are predicated on long-term, continuous exposure to a substance.

For benzene, the current RfC (30 $\mu\text{g}/\text{m}^3$) and URF values (13 to 45 $\mu\text{g}/\text{m}^3$) indicate that long term exposure to benzene at a concentration equal to its current AAS (12 $\mu\text{g}/\text{m}^3$) is not expected to pose unacceptable carcinogenic or noncarcinogenic health effects. Moreover, as shown in the above table, the maximum modeled concentration of benzene is only 5% of its AAS.

In sum, there will be no adverse impacts to public health or the environment resulting from Nucor's benzene emissions.

Comment No. II.4

THE PROPOSED PERMITS AND LDEQ'S ACTIONS MUST CONSIDER ENVIRONMENTAL JUSTICE CONCERNS AND IMPACTS ON MINORITY COMMUNITIES.

LDEQ is required to carry out its responsibilities in a nondiscriminatory manner in accordance with the requirements of Title VI of the Civil Rights Act of 1964, as amended, 42 U.S.C. §§ 2000d to 2000d-7 (Title VI), EPA's implementing regulations at 40 C.F.R. Part 7, and the Agreement Between The Louisiana Department of Environmental Quality and the United State Environmental Protection Agency (Jan. 18, 2005). Accordingly, LDEQ must take into consideration cumulative adverse health and environmental impacts on the affected community from the multiple pollution sources in the area when making its permit decisions. LDEQ must detail its analysis and reasoning on this issue and take into consideration any findings of the Mississippi River Corridor Task Force (established by Executive Order MJF 98-01). Furthermore, since the proposed site for the pig iron and DRI steel complex encompasses the same site identified by Shintech for its PVC facility, LDEQ must update and consider the demographic analysis of the area compiled by EPA when EPA investigated a complaint against LDEQ for violating Title VI and 40 C.F.R. Part 7. *See* Title VI Admin. Complaint Re: Louisiana Department of Environmental Quality, Permit for Proposed Shintech Facility, Summary Documentation of Draft Revised Demographic Analysis (April 1998), available at www.epa.gov/civilrights/docs/shintech/apr98/cover48.pdf.

LDEQ Response to Comment No. II.4

Regarding Title VI of the Civil Rights Act, see Section V of LDEQ's Basis for Decision. In sum, with respect to the NAAQS-covered pollutants, EPA's position is that where an air quality concern is raised regarding a pollutant regulated pursuant to an ambient, health-based standard, and where the area in question is in compliance with, and will continue after the operation of the challenged facility to comply with, that standard, the air quality in the surrounding community is presumptively protective, and emissions of that pollutant should not be viewed as "adverse" within the meaning of Title VI.²⁸

By establishing an ambient, public health threshold, standards like the NAAQS contemplate multiple source contributions and establish protective limits on cumulative emissions that should ordinarily prevent an adverse air quality impact. The modeling results reviewed and accepted by LDEQ account for the multiple pollution sources in the area.

LDEQ accepts the EPA's assessment and reasoning. Nucor's modeling shows the proposed facility will, with the controls installed pursuant to applicable federal and state standards and LDEQ's BACT determinations, meet or exceed the primary and secondary NAAQS in the area surrounding the facility. Accordingly, there can be no "adverse" and "disparate" impact in these areas.

The modeling associated with the initial permits for the pig iron manufacturing facility did show several exceedances of the NAAQS; however, as explained in Section IV.D.1.c of LDEQ's Basis for Decision associated with Permit No. 2560-00281-V0, Nucor's contribution to each exceedance was minimal and within regulatory allowances.²⁹ Moreover, as explained in LDEQ Response to Comment No. I.1, the modification to the Title V permit for the pig iron manufacturing facility will result in substantial reductions in potential emissions of criteria pollutants.

In the case referenced by the commenter regarding Shintech, the Title VI complaint alleged that African Americans in St. James Parish are disproportionately affected by LDEQ's permitting of facilities with toxic emissions. EPA used 1995 Toxics Release Inventory (TRI) and 1996 Toxic

²⁸ EPA's reasoning is discussed further in Section V of LDEQ's Basis for Decision documents.

²⁹ EDMS Doc ID 2947527 (pp. 17 – 22)

Emissions Data Inventory (TEDI) data in its analyses. Therefore, LDEQ re-examined current TRI and TEDI emissions in this geographic area. 2009 data is the most recent available in each case. The results are as follows:

St. James Parish

TRI Total On- and Off-Site Disposal or Other Releases (pounds)³⁰

<u>1995</u>	<u>2009</u>	<u>Change</u>	<u>Percent Change</u>
14,704,486	4,936,766	-9,767,720	-66.4%

Toxic Air Pollutant (TAP) Emissions (pounds)³¹

<u>1996</u>	<u>2009</u>	<u>Change</u>	<u>Percent Change</u>
7,616,809	3,076,874	-4,539,935	-59.6%

These results were compared to the changes in Louisiana.

Louisiana

TRI Total On- and Off-Site Disposal or Other Releases (pounds)

<u>1995</u>	<u>2009</u>	<u>Change</u>	<u>Percent Change</u>
181,314,837	119,527,406	-61,787,431	-34.1%

Toxic Air Pollutant (TAP) Emissions (pounds)

<u>1996</u>	<u>2009</u>	<u>Change</u>	<u>Percent Change</u>
105,021,727	38,847,682	-66,174,045	-63.0%

As evidenced above, there have been substantial reductions in both TRI-reportable releases and toxic air emissions since the Title VI complaint was lodged. The percent reduction in TRI-reportable releases in St. James Parish was substantially greater than the state-wide figure, whereas the percent reduction in TAP emissions was on par with the state-wide figure.

Moreover, though criteria pollutant emissions were not addressed in the Title VI response, there has also been an appreciable decline in such emissions in St. James Parish since the report in question was released.

Criteria Pollutant Emissions (tons)³²

<u>Pollutant</u>	<u>1996</u>	<u>2009</u>	<u>Change</u>
PM ₁₀	810.0	1317.9	+ 507.9
SO ₂	24,717.1	8609.2	- 16,107.9
NO _x	9435.8	5097.8	- 4338.0
CO	3425.8	2430.2	- 995.6
VOC	1882.5	1196.0	- 686.5

³⁰ TRI data obtained from <http://www.epa.gov/triexplorer/>.

³¹ TAP emissions data obtained from <http://www.deq.louisiana.gov/portal/default.aspx?tabid=1758>.

³² EI data obtained from <http://www.deq.louisiana.gov/portal/default.aspx?tabid=1758>.

40,271.2	18,651.1	- 21,620.1
	Percent Change::	- 53.7%

III. Responses to Comments Submitted by Pless Environmental, Inc. via the Tulane Environmental Law Clinic³³

Comment No. III.1

I. The Draft PSD Permit Fails to Determine the Applicability of PSD for GHGs

While the draft PSD permit apparently recognizes that the DRI facility is subject to PSD for GHGs – as it provides GHG BACT analyses for several emissions units – it does not provide a determination of PSD applicability. Thus, the draft PSD permit fails to follow proper procedure.

Over the past year, the U.S. Environmental Protection Agency (“EPA”) has taken several actions regarding GHGs under the Act. As a result, certain PSD permits and certain Title V permits issued on or after January 2, 2011, must address emissions of GHGs.

On April 2, 2010, EPA published a final decision to continue applying the Agency’s existing interpretation regarding when a pollutant becomes “subject to regulation” under the Act. Under this interpretation, GHGs became “subject to regulation” when the national emissions standards for GHGs from light-duty vehicles went into effect on January 2, 2011.

On June 3, 2010, the EPA issued the final *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule* (“Tailoring Rule”). This rule “tailors” the applicability provisions of the PSD and Title V programs under the Act to enable EPA and states to phase in permitting requirements for GHGs. Beginning on January 2, 2011, GHGs are a “regulated” New Source Review (“NSR”) pollutant under the Act’s PSD major source permitting program when they are emitted by new sources or modifications in amounts that meet the Tailoring Rule’s set of applicability thresholds, which phase in over time.

The Tailoring Rule does not change the basic PSD applicability process for evaluating whether a source is a new major source or modification. However, due to the nature of GHGs and their incorporation into the definition of “regulated” New Source Review (“NSR”) pollutant under the Act, the process to determine whether a source is emitting GHGs in an amount that would make GHGs a regulated NSR pollutant includes a comparison of the source’s CO₂-equivalent (“CO₂e”) emissions as well as its GHG mass emissions to certain applicability thresholds. Consequently, when determining the applicability of PSD to GHGs, there is a two-part applicability process that evaluates both:

- The sum of the CO₂e emissions (in tons/year) of the six GHGs, in order to determine whether the source’s GHG emissions are a regulated NSR pollutant; and, if so

³³ EDMS Doc ID 7781463

- The sum of the mass emissions (in tons/year) of the six GHGs, in order to determine if there is a major source or major modification of such emissions.

The first step of the Tailoring Rule, which began on January 2, 2011 and ends on June 30, 2011, covers what EPA calls “anyway sources” and “anyway modifications” that would be subject to PSD “anyway” based on emissions of NSR pollutants other than GHGs. The second step begins on July 1, 2011, and continues thereafter to cover both anyway sources and certain other large emitters of GHGs.

For new sources with PSD permits issued from January 2, 2011, to June 30, 2011, Tailoring Rule Step 1 specifies that PSD is applicable for GHGs if both of the following conditions are true:

- a) Not considering its emissions of GHGs, the new source is considered a major source for PSD applicability and is required to obtain a PSD permit (called an “anyway source”); *and*
- b) The potential emissions of GHGs from the new source would be equal to or greater than 75,000 tons/year on a CO₂e basis.

As determined by the draft PSD Permit, the DRI facility is “subject to PSD anyway” due to emissions of particulate matter (“PM”), particulate matter with an aerodynamic diameter of 10 micrometers or less (“PM₁₀”), particulate matter with an aerodynamic diameter of 2.5 micrometers or less (“PM_{2.5}”), sulfur dioxide (“SO₂”), nitrogen oxides (“NO_x”), carbon monoxide (“CO”), and volatile organic compounds (“VOC”) and therefore satisfies Condition (a) of Tailoring Rule Step 1.

The draft permits fail to provide an estimate for potential emissions of GHGs from the DRI facility on a CO₂e basis, as required by Condition (b) of Tailoring Rule Step 1. However, GHG emissions can be approximated as follows: LDEQ determined in its BACT analysis for the Reformer/Main Flue Gas Stack (DRI-108/208) that BACT for GHG emissions would be natural gas consumption of no more than 13 decatherms of natural gas per metric ton (“tonne”) of DRI produced and implemented this BACT determination in Specific Condition #81. Based on the proposed maximum annual production of 5.0 million tonnes of DRI per year and the limit on annual natural gas consumption of 13 decatherms of natural gas per tonne of DRI produced, CO₂ emissions from the Reformer/Main Flue Gas Stack (DRI 108/208) can be estimated at roughly 3.8 billion tons CO₂e/year. (For a discussion of the BACT limit on natural gas consumption, *see* Comments II.B.1 and II.B.2.) Thus, not accounting for any other GHG emissions from the DRI facility, GHG emissions from natural gas consumption for the Reformer/Main Flue Gas Stack (DRI-108/208) alone would clearly exceed the 75,000 ton/year threshold for GHG emissions set in Tailoring Rule Step 1, Condition (b). Therefore, the facility is subject to PSD for GHGs as a regulated NSR pollutant.

LDEQ Response to Comment No. III.1

The commenter provides a lengthy explanation of how to determine if greenhouse gases (GHGs) must be regulated under the Prevention of Significant Deterioration (PSD) program, an analysis

with which LDEQ agrees. However, the suggestion that the “draft PSD permit fails to follow proper procedure” by not satisfying “Condition (b) of Tailoring Rule Step 1” is unfounded.

EPA’s final “Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule” amends 40 CFR 51.166 and 40 CFR 52.21 by adding the definition of “subject to regulation” and revising the definition of “regulated NSR pollutant.”³⁴ It does not mandate that “an estimate for potential emissions of GHGs” be included in a PSD permit “on a CO₂e basis.” Permit Nos. 3086-V0 and PSD-LA-751 appropriately conclude that GHG emissions from the DRI plants are subject to the PSD program, evidenced by LDEQ’s best available control technology (BACT) determination for CO₂e.

LDEQ estimates CO₂ emissions from the DRI plants to be approximately 3.39 million metric tons per year (equivalent to 3.73 million standard tons) based on the BACT limit of 13 decatherms of natural gas per metric ton of DRI. LDEQ derives this estimate in the following manner:

$$[13 \text{ MMBtu} / \text{tonne of DRI}] \times [5,000,000 \text{ tonnes of DRI}] = 65,000,000 \text{ MMBtu}$$

$$[65,000,000 \text{ MMBtu}] \times [1,000,000 \text{ Btu} / \text{MMBtu}] = 65 \times 10^{12} \text{ Btu}$$

$$[65 \times 10^{12} \text{ Btu}] / [23,879 \text{ Btu} / \text{lb methane}] = 2,722,057,038 \text{ lbs methane}$$

$$[2,722,057,038 \text{ lbs methane}] / [16.04 \text{ lbs of methane} / \text{mol}] = 169,704,304 \text{ mols}$$

$$[169,704,304 \text{ mols}] \times [44.01 \text{ lbs CO}_2 / \text{mol}] = 7,468,686,423 \text{ lbs CO}_2$$

$$[7,468,686,423 \text{ lbs CO}_2] / [2,000 \text{ lbs} / \text{ton}] = 3,734,343 \text{ tons CO}_2$$

$$[3,734,343 \text{ tons CO}_2] / [1.102 \text{ tons} / \text{tonne}] = 3,388,696 \text{ tonnes CO}_2$$

This figure should be viewed as conservative (i.e., as overstating CO₂ emissions), as it does not discount the carbon molecules that will remain in the DRI product.

Comment No. III.2

The BACT Analyses for GHG Emissions from the DRI Facility Provided in the Draft PSD Permit Are Fatally Flawed and, as a Result, the Draft Permits Fails to Require BACT

Under the CAA and corresponding implementing regulations, each new source or modified emissions unit subject to PSD must install and operate state-of-the-art pollution controls, known as best available control technology (“BACT”) for each pollutant subject to regulation under the Act. Consequently, the draft PSD Permit for the DRI facility must contain a BACT analysis for GHGs that satisfies the requirements of the Act.

The Louisiana Administrative Code (“LAC”) defines BACT as:

- a. an emissions limitation, including a visible emission

³⁴ 75 FR 31606 – 31607

standard, based on the maximum degree of reduction for each pollutant subject to regulation under this Section that would be emitted from any proposed major stationary source or major modification that the administrative authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant;

b. in no event shall application of *best available control technology* result in emissions of any pollutant that would exceed the emissions allowed by an applicable standard under 40 CFR Parts 60 and 61. If the administrative authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of *best available control technology*. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice, or operation, and shall provide for compliance by means that achieve equivalent results.

To aid permitting agencies in implementing the Act's statutory requirement that BACT represent the maximum degree of reduction, the EPA has established a five step top-down analysis process that is described in the New Source Review Manual ("NSR Manual"). This guidance is widely used by permitting engineers and agencies to make BACT determinations and by the Environmental Appeals Board ("EAB") in deciding appeals of PSD cases." The top-down BACT analysis methodology is standard operating procedure. A PSD permit was recently remanded to Michigan's Department of Environmental Quality ("MDEQ") for failing to follow the NSR Manual.

LDEQ should follow consistently the top-down process as laid out in the NSR Manual – to do otherwise would be contrary to LDEQ's duty to provide a rational basis for its decisions as the steward for the environment.

The NSR Manual details the necessary process for determining "top-down" BACT, as required by 42 U.S.C. § 7475. This five-step process is conducted to ensure that a valid BACT determination has been made:

- STEP 1: *Identify all control technologies.* This list must be comprehensive and include all lowest achievable emission rates ("LAER").
- STEP 2: *Eliminate technically infeasible options.* A demonstration of technical infeasibility should be clearly documented and must show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

- STEP 3: *Rank remaining control technologies by control effectiveness.* This includes:
 - control effectiveness (percent pollutant removed);
 - expected emission rate (tons per year and pounds per hour);
 - expected emission reduction (tons per year);
 - energy impacts;
 - environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
 - economic impacts (total cost effectiveness, incremental cost effectiveness)
- STEP 4: *Evaluate most effective controls and document results.* This must include a case-by-case consideration of energy, environmental, and economic impacts. If top option is not selected as BACT, evaluate next most effective control option.
- STEP 5: *Select BACT.* The most effective option not rejected is BACT.

In November 2010, EPA published the *PSD and Title V Permitting Guidance for Greenhouse Gases* (“EPA GHG Permitting Guidance”) to assist permit writers and permit applicants in addressing the PSD and Title V permitting requirements for GHGs. This guidance recommends that permitting authorities continue to use the five-step top-down BACT process to determine BACT for GHGs and provides a discussion of how each step may apply to the aspects that are unique to GHGs.

GHG BACT Analyses for Proposed DRI Facility

In a typical BACT process, the Applicant prepares an initial analysis that is submitted to the permitting agency. The agency reviews the analysis, requests additional information, conducts independent analyses, and makes an independent determination. A draft permit is then prepared based on the BACT analysis that is reviewed by the Applicant and the public. The permitting agency reviews and responds to comments received on its draft determination and issues a final BACT determination, which is subject to EPA’s review and oversight.

The Applicant submitted a BACT analysis for GHG emissions from the DRI facility to satisfy the requirements of the Tailoring Rule. However, instead of following the recommended five-step top-down approach for BACT analyses, the Applicant’s GHG BACT Analysis consists of a mere four-page discussion including:

- a) a description of steel recycling and iron manufacturing (including pig iron and DRI);
- b) the conclusion that natural gas consumption is the most relevant parameter that can be measured for the DRI process;
- c) a discussion of the potential for minimizing natural gas consumption (including removal of oxygen from the recycle loop of reducing gas, removal of water vapor from spent reducing gas, installation of an acid gas removal system, energy integration through recycling spent reducing gas as top-gas, good combustion practices with low-NOx burners);

- d) a discussion of historical rates of natural gas consumption per unit of DRI produced;
- e) identification of a facility-wide limit for natural gas consumption (13 decatherms/tonne DRI produced) as BACT for GHG emissions; and
- f) recommendations for compliance monitoring of natural gas consumption (using fuel consumption tracking method as well as mass balance approach).

The Applicant's GHG BACT Analysis contains no documentation, citations, calculations, or discussion of alternative DRI processes.

Based on the Applicant's GHG BACT Analysis, LDEQ proposes best available control technologies for GHG emissions for the Package Boiler (DRI-109/209), the Reformer/Main Flue Gas Stack (DRI-108/208), and the Acid Gas Absorption Vent ("DRI-111/211), as summarized in Table 1.

Table 1: Proposed CO_{2e} BACT*

Emission Source	Source Identifier	Proposed CO_{2e} BACT
Package Boiler	DRI-109 DRI-209	Good combustion practices
Reformer / Main Flue Stack	DRI-108 DRI-208	Good combustion practices, acid gas separation, energy integration
Acid Gas Absorption Vent	DRI-111 DRI-211	Acid gas separation system

* Source: Draft PSD Permit for DRI Facility, PSD-LA-751, November 8, 2010, Briefing Sheet, p. 4, EDMS Document 7731649, p. 63 of 823; and Draft Part 70 Air Operating Permit for DRI Facility, Statement of Basis, p. 11, EDMS Document 7731649, p. 141 of 823.

In an attempt to follow the five-step top-down BACT analysis framework in the draft PSD Permit BACT determination section, LDEQ paraphrases portions of the Applicant's GHG BACT Analysis for two of the DRI facility's emission units in each train: the Package Boiler (DRI-109/209) and the Reformer/Main Flue Gas Stack (DRI-108/208). No such top-down BACT analysis is provided for the Acid Gas Absorption Vent (DRI-111/211), even though the source is previously identified as a unit subject to BACT for GHGs. LDEQ provides little additional discussion, documentation, citations, or calculations to support its BACT analyses. A proper BACT determination must include both supporting factual documentation and a detailed discussion of the permit authority's decision-making process. An applicant bears the burden of demonstrating that a control option is either commercially unavailable or inapplicable to the project, that an available technology is technically infeasible, and that the selected control technology will actually achieve BACT. This demonstration must include adequate technical documentation.

LDEQ's analyses do not satisfy the definition of BACT and the top-down BACT process for numerous reasons including: (1) the failure to document BACT

decisions; (2) the failure to identify all potentially available control options; (3) the failure to identify GHG emission rates; (4) the erroneous determination of a BACT emission limitation; (5) the failure to require the identified BACT control technology in the draft permits; and (6) the failure to establish enforceable conditions; (7) and procedures for establishing GHG emissions. Therefore, the draft PSD Permit fails to satisfy the requirements of the Act regarding BACT for GHG emissions from the DRI facility.

LDEQ Response to Comment No. III.2

LDEQ's duty to provide a rational basis for its decisions is not somehow intrinsically linked to the "top down" BACT process as laid out in EPA's draft 1990 New Source Review Workshop Manual (NSR Manual).

Because the comments rely heavily on statements from the NSR Manual, it is imperative to recognize that this document remains in "draft" form and was never formally adopted by EPA as agency guidance. In fact, the preface to the NSR Manual states, "It [the NSR Manual] is not intended to be an official statement of policy and standards and does not establish binding regulatory requirements; such requirements are contained in the regulations and approved state implementation plans."

Nevertheless, many people have looked to this document for guidance and have sometimes improperly construed the NSR Manual to contain requirements that must be followed. To avoid any misunderstandings concerning the effect of the NSR Manual, EPA has explicitly stated that it is not a binding regulation and does not by itself establish final EPA policy or authoritative interpretations of EPA regulations under the NSR program.³⁵

The EPA's Environmental Appeals Board ("Board") has sometimes referenced the draft NSR Manual as a reflection of our thinking on certain PSD issues, but the Board has been clear that the draft NSR Manual is not a binding Agency regulation. *See*, In re: Indeck-Elwood, LLC, PSD Permit Appeal No. 03-04, slip. op. at 10 n. 13 (EAB Sept. 27, 2006); In re: Prairie State Generating Company, PSD Permit Appeal No. 05-05, slip. op. at 7 n. 7 (EAB Aug 24, 2006). In these and other cases, the Board also considered briefs filed on behalf of the Office of Air and Radiation that provided more current information on the thinking of the EPA headquarters program office on specific PSD issues arising in particular cases. Thus, the Board has looked to the draft NSR Manual as one resource to consider in developing Agency positions through case-by-case adjudications, while recognizing that the draft NSR Manual does not itself contain binding requirements.³⁶

Notably, it remains EPA's *policy* to use the five-step, top-down process to satisfy the BACT requirements when PSD permits are issued by EPA and delegated permitting authorities, and EPA continues to interpret the BACT requirement in the CAA and EPA regulations to be satisfied when BACT is established using this process. However, notwithstanding this policy and the interpretations of the BACT requirement reflected in EPA adjudications, EPA has not established the top-down BACT process as a binding requirement through regulation.

³⁵ Proposed "Prevention of Significant Deterioration New Source Review: Refinement of Increment Modeling Procedures," 72 FR 31372 (June 6, 2007)

³⁶ 72 FR 31376 – 31377

The commenter also cites EPA’s “PSD and Title V Permitting Guidance For Greenhouse Gases” (GHG Guidance)³⁷ released on November 10, 2010. Nucor’s “Direct Reduced Iron Facility GHG BACT Analysis”³⁸ was submitted on October 22, 2010, prior to the release of this document. As such, LDEQ’s review of Nucor’s submittal was conducted, in large part, without the benefit of EPA’s guidance.

The commenter expresses concern about the amount of documentation in the record. Thus, it is important to understand that limited data is currently available regarding control of greenhouse gases. EPA’s GHG Guidance acknowledges that:

“[T]here is little history of BACT analyses for GHG at this time ...”³⁹

In the initial phase of PSD permit reviews for GHGs, background information about certain emission control strategies may be limited and technologies may still be under development.⁴⁰

This guidance is being issued at a time when add-on control technologies for certain GHGs or emissions sources may be limited in number and in various stages of development and commercialization.⁴¹

In addition to the guidance noted above, EPA has released a number of technical “white papers” summarizing readily available information on control techniques and measures to reduce GHG emissions from specific industrial sectors. One such paper targets the iron and steel industry.⁴² Notably, this document does not address control techniques or measures to mitigate GHG emissions from facilities that produce DRI, though an integrated DRI/EAF steelmaking facility was highlighted as an “emerging technology.”⁴³ Moreover, the iron and steel industry sector is not addressed in EPA’s Greenhouse Gas Mitigation Strategies Database, nor is relevant data located in EPA’s RACT/BACT/LAER Clearinghouse.

Regarding the Acid Gas Absorption Vents, the only available control options identified were dedicated sequestration and transport and sequestration. See LDEQ Response to Comment No. III.5.

The commenter’s other allegations are addressed in LDEQ Response Comment Nos. III.4, III.5, III.7, III.8, and III.9.

Comment No. III.3

II.A LDEQ’s GHG BACT Analyses Fail to Consider All Potentially Available Control Options

³⁷ <http://www.epa.gov/nsr/ghgdocs/epa-hq-oar-2010-0841-0001.pdf>

³⁸ EDMS Doc ID 7718227

³⁹ “PSD and Title V Permitting Guidance For Greenhouse Gases,” pg. 44.

⁴⁰ *Ibid.*, pg. 34.

⁴¹ *Ibid.*, pg. 36.

⁴² “Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Iron and Steel Industry,” October 2010, available at <http://www.epa.gov/nsr/ghgpermitting.html>.

⁴³ *Ibid.*, pg. 40 of 69.

The first step in the top-down BACT process is to identify all “available” control options including the application of alternative production processes, methods, systems, and techniques, including clean fuels or treatment or innovative fuel combustion techniques for control of the affected pollutant. In some circumstances, inherently lower-polluting processes are appropriate for consideration as available control alternatives. According to EPA, potentially applicable control options that should be identified and evaluated in a BACT analysis can be grouped into the following three categories of potentially available control options:

- Inherently lower-emitting processes/practices/designs.
- Add-on controls, and
- Combinations of inherently lower emitting processes/practices/designs and add-on controls.

While Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant.

The EPA states that BACT should generally not be applied to regulate the applicant’s purpose or objective for the proposed facility. In assessing whether an option would fundamentally redefine a proposed source, EPA recommends that permitting authorities “consider how the applicant defined its goal, objectives, purpose or basic design for the proposed facility in its application... The permitting authority should then take a “hard look” at the applicant’s proposed design in order to discern which design elements are inherent for the applicant’s purpose and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant’s basic business purpose for the proposed facility. In doing so, the permitting authority should keep in mind that BACT, in most cases, should not be applied to regulate the applicant’s purpose or objective for the proposed facility. This approach does not preclude a permitting authority from considering options that would change aspects (either minor or significant) of an applicants’ proposed facility design in order to achieve pollutant reductions that may or may not be deemed achievable after further evaluation at later steps of the process.” EPA recommends that a BACT analysis include an evaluation of energy efficiency. Although CCS is not in widespread use at this time, EPA generally considers carbon capture and storage (“CCS”) to be an “available” add-on pollution control technology for large CO₂-emitting facilities and industrial facilities with high-purity CO₂ streams such as iron and steel manufacturing.

LDEQ’s BACT analyses for GHG emissions from the DRI facility identify good combustion practices for the Package Boiler (DRI-109/209) and good combustion practices, acid gas separation and energy integration for the Reformer/Main Flue Gas Stack (DRI-108/208) as inherently-lower emitting processes/practices/designs but fail to provide an evaluation of energy efficiency, for example, of alternative DRI production processes, and of CCS.

LDEQ Response to Comment No. III.3

Alternative DRI production processes and energy efficiency are addressed in LDEQ Response to Comment No. III.4; carbon capture and storage is addressed in LDEQ

Response to Comment No. III.5.

Comment No. III.4

II.A.1 Energy Efficiency of Alternative DRI Production Processes

The Applicant contends that “the DRI process itself should be viewed as a distinct process that provides significant GHG reductions when compared with the pig iron production process” and claims that “to the extent that DRI can be used in lieu of pig iron, DRI would be the preferential raw material because of the approximate 75% reduction in GHG releases.” The Applicant provides no support for these claims and LDEQ did not provide any additional information.

Worldwide, dozens of different processes are employed for direct reduction of iron. The three major natural gas-based processes are: Midrex (Midrex), HYL/Energiron (Tenova/ Danieli/HYL), and Finmet (Selas-Linde). Currently, about 73% of the world DRI production is accounted for by the two shaft furnace-based processes Midrex and HYL/Energiron. In the beginning of 2009, the total installed capacity of these processes worldwide was 55.7 million tons/year per ton of DRI including 58 Midrex modules (capacity 40.6 million tons/year per ton of DRI) and 26 HYL/Energiron modules (capacity 15.1 million tons/year of DRI). Other gas-based processes, including the fluidized-bed reactor-based Finmet technology, accounted for an installed capacity of 2.2 million tons/year of DRI worldwide.

Further, HYL/Energiron is also developing a new process, the HYL ZL reformerless technology. The manufacturer of this technology provides that by eliminating the need for a reformer, overall energy efficiency would be optimized by integrating partial combustion, pre-reforming, and in-situ reforming inside the shaft furnace and the use of thermal equipment in the plant would be lowered, which could dramatically reduce GHG emissions. The Applicant has stated that [*sic*] is considering and is seeking, as an alternative operating scenario, an authority to construct the reformer-less HYL process. However, neither the draft PSD Permit nor the draft PSD Permit evaluate this alternative as a potential available control technology for reducing GHG (and criteria pollutant) emissions from the DRI facility. There is no application nor are there any emission calculations for this option.

However, it appears that the Applicant and LDEQ have been discussing the potential effects of this alternate operating scenario. For example, the Worksheet for Technical Review of the Working Draft of the Proposed Permit discusses the draft Title V Permit Specific Requirement #316. The Applicant stated that “[t]here is no Alternate Operating Scenario for this requirement to affect.” LDEQ’s response stated that “additional language was added,” which appears to refer to Section XI, Operational Flexibility, in the draft Title V Permit Statement of Basis rather than a change in the Specific Requirement. In fact, the Specific Requirement with the highest running number is #313, indicating that Specific Requirements #314 through #316 have been eliminated. Nevertheless, the draft Title V Permit states that “Nucor is investigating the potential of a DRI process that does not require a reformer as part of the design” in which the reformer would be replaced by a process heater providing the energy input necessary to heat the furnace. This potential process change must be evaluated as part of the PSD and Title V permit process.

The energy efficiency of these alternative processes for DRI production must be

evaluated in a BACT analysis for GHG emissions from the proposed DRI facility as they would not fundamentally redefine the proposed source and would not require changing the fuel for the facility.

LDEQ Response to Comment No. III.4

Alternative DRI production processes are only relevant to the extent they can produce the product desired by Nucor and result in fewer emissions of regulated NSR pollutants, including criteria pollutants and greenhouse gases.

Additionally, in order to be considered a technically feasible BACT alternative, a technology should be commercially available. LDEQ's research could not identify an installation of the HYL ZR reformerless technology on anything close to the scale of the units proposed by Nucor. Much smaller units, such as the 200,000 tonne per year facility in Abu Dhabi and the 650,000 tonne per year facility in Monterrey, Mexico, are an order of magnitude smaller than the facility proposed by Nucor. HYL has not even proposed process units based on the HYL ZR design as large as the facility applied for by Nucor, and so LDEQ believes that this design cannot be deemed commercially available on this scale. See LDEQ Response to Comment No. III.7.

Per its "IT Questions Response," Nucor is "seeking a permit for a traditional, reformer-based DRI facility, but is also seeking authority to construct, in the alternative, the reformer-less HYL process unit."⁴⁴ However, LDEQ does not issue permits with undefined alternative operating scenarios, and received no calculations or process drawings pertaining to a reformerless design. Permit Nos. 3086-V0 and PSD-LA-751 only authorize construction and operation of the emissions units addressed therein; they do not allow Nucor to construct reformerless process units.

Specific Requirement 316 of the version of the Title V permit offered for technical review read as follows:

Alternate Operating Scenario: Operating plan recordkeeping by logbook upon each occurrence of making a change from one operating scenario to another. Record the operating scenario under which the facility is currently operating. Include in this record the identity of the sources involved, the permit number under which the scenario is included, and the date of change. Keep a copy of the log on site for at least two years. [LAC 33:III.507.G.5]

This condition appeared in the proposed Title V permit available for public comment as Specific Requirement 293. Specific Requirements are sorted by citation. Accordingly, a given requirement may be renumbered if other requirements are added or removed.

Because no alternate operating scenario exists, this requirement has been removed from the permit.

Comment No. III.5

II.A.2 Carbon Capture and Storage

EPA recommends that CCS be listed in Step 1 of a top-down BACT analysis for GHGs. The EPA states that this "does not necessarily mean CCS should be selected

⁴⁴IT Questions Response, Section 7.1.2 (EDMS Doc ID 7731649)

as BACT for such sources. Many other case-specific factors, such as the technical feasibility and cost of CCS technology for the specific application, size of the facility, proposed location of the source, and availability and access to transportation and storage opportunities, should be assessed at later steps of a top-down BACT analysis. However, for these types of facilities and particularly for new facilities, CCS is an option that merits initial consideration and, if the permitting authority eliminates this option at some later point in the top-down BACT process, the grounds for doing so should be reflected in the record with an appropriate level of detail.”

The Applicant explains that the proposed acid gas separation system would make CO₂ available in near-pure form for other uses. However, the Applicant states that until infrastructure and a commercial alternative exists for the distribution of purified CO₂ it will vent this stream to the atmosphere. However, the Applicant provides that “by having the capacity to distribute carbon dioxide for the purposes of enhanced oil recovery, or some other purpose, Nucor believes it has met the requirements to have the best available technology [sic] at the facility for the reduction of GHG emissions.”

The draft PSD Permit in Step 1 of the GHG BACT analysis for the Reformer/Main Flue Gas Stack (DRI-108/208) provides the following discussion:

Current DRI process designs release carbon dioxide from the process gas loop by off-taking a stream of spent reducing gas (prior to recycle back to the reformer) and using this stream as fuel in the reformer. Carbon dioxide is born in the fuel gas and simply passes through the combustion process as an inert. While this increases the energy efficiency of the reformer by providing more gases to surround the reformer tubes for heat transfer, the carbon dioxide is still released to the atmosphere.

...

An acid gas removal system using an amine absorber system has the ability to separate carbon dioxide from the spent reducing gas prior to combustion in the reformer. After treatment for sulfur compounds, the resulting gas is nearly pure carbon dioxide, which may require little additional processing effort to produce pipeline-quality, commercial grade CO₂. Removing CO₂ from the spent reducing gas has the added benefit of increasing combustion efficiency in the reformer.

The draft PSD Permit contains no discussion of the “little additional processing effort” that would be required to produce a commercial grade CO₂ stream nor does it require that a suitable process be installed at the facility. Further, the draft PSD Permit contains no discussion whatsoever of potential commercial uses of CO₂ including, for example, the installation of a pipeline to existing enhanced oil recovery operations, or the use of CCS as an add-on pollution control technology for GHGs. The draft PSD Permit should be revised to address these issues.

LDEQ Response to Comment No. III.5

LDEQ has determined that an acid gas separation system is BACT for GHG emissions for the Reformer Main Flue Stacks (DRI-108/DRI-208). The “Step 5 – Section of BACT” discussion in PSD-LA-751 pertaining to the Reformer Main Flue Gas Stacks (DRI-108/208) will be

clarified to indicate that BACT for CO₂e is good combustion practices, an acid gas separation system, and energy integration.

Regarding carbon capture and storage (CCS), EPA suggest that such systems are “an add-on pollution control technology that is ‘available’ for large CO₂-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO₂ streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).”⁴⁵

Thus, LDEQ has evaluated both dedicated sequestration and transport and sequestration.

Dedicated Sequestration

Dedicated sequestration involves the injection of CO₂ into an on-site or nearby geological formation, such as an active oil reservoir (enhanced oil recovery), a brine aquifer, an un-mined coal seam, basalt rock formation, or organic shale bed. Clearly, in order for geologic sequestration to be a feasible technology, a promising geological formation must be located at or very near to the facility location.

According to the U.S. Department of Energy’s (DOE),⁴⁶ no basalt formations exist any nearer to the project site than Alabama. Organic-rich shale basins and un-mineable coal areas exist in northern Louisiana, but not in the region of southeast Louisiana where the facility will be located.

Saline formations are layers of porous rock that are saturated with brine. These formations are known to exist throughout southern Louisiana. However, as described by the DOE, “less is known about saline formations because they lack the characterization experience that industry has acquired through resource recovery from oil and gas reservoirs and coal seams. Therefore, there is an amount of uncertainty regarding the suitability of saline formations for CO₂ storage.”⁴⁷ LDEQ was unable to find characterization studies of saline formations in the region of southeastern Louisiana, including in the vicinity of the project site in Convent, and no saline sequestration projects have been proposed along the Gulf coast. Due to the high degree of uncertainty in utilizing saline formations for dedicated CO₂ storage, this type of sequestration was deemed technically infeasible.

Louisiana is well known as a major producer of oil and natural gas; therefore, the sequestration of CO₂ in oil and gas reservoirs through enhanced oil recovery techniques may be feasible. While St. James Parish serves as a major transshipment corridor for natural gas, petroleum, and petroleum products, it was found that very few oil and gas wells exist in St. James Parish and the vicinity of Convent. The nearby Maurepas Swamp basin is virtually devoid of oil and gas production. One active field exists in St. James Parish on the west bank of the Mississippi River, but this field is a natural gas producer and is not depleted; CO₂ injected here would simply be reclaimed by natural gas production operations. Without a nearby active oil reservoir, or depleted natural gas reservoir, this option becomes technically infeasible.

Transport and Sequestration

⁴⁵ “PSD and Title V Permitting Guidance For Greenhouse Gases,” November 2010, pp. 33 – 34

⁴⁶ “2010 Carbon Sequestration Atlas of the United States and Canada,” Third Edition, U.S. Dept. of Energy, National Energy Technology Laboratory. See http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/.

⁴⁷ *Ibid.*, p. 27.

Off-site sequestration of CO₂ involves utilization of a third-party CO₂ pipeline system in order to transport CO₂ to distant geologic formations that may be more conducive to sequestration than sites in the immediate area. Building such a pipeline for dedicated use by a single facility is almost certain to make any project economically infeasible. However, such an option may be effective if both adequate storage capacity exists downstream and reasonable transportation prices can be arranged with the pipeline operator.

Denbury Resources operates a dedicated CO₂ pipeline in the general area of the proposed location of the Nucor facilities. However, the nearest branch of this pipeline is approximately 8 miles distant and across the Mississippi River. Access to this pipeline without a river crossing is approximately 20 miles. In order for use of Denbury's pipeline to be viable, Nucor would, of course, have to connect to it. To do so, Nucor would have to secure the necessary right-of-ways (or perhaps purchase additional property), construct a 20-mile pipeline (or if the shorter leg is selected, tunnel under the Mississippi River), purchase additional compression equipment with ongoing electricity and maintenance requirements, and likely obtain the approval of other regulatory agencies. In sum, the feasibility of connecting to Denbury's CO₂ pipeline, both from a logistical and an economic perspective, is, at best, unknown.

LDEQ is also concerned about any permit condition which would, in effect, direct Nucor to contract with a specific, single third party that would act in the capacity of an essential utility, especially given that Denbury's CO₂ pipeline is not regulated by the Louisiana Public Service Commission. LDEQ's position is that any such condition, regardless of the individual circumstances, is beyond the scope of a BACT determination. For this reason, transport and sequestration was eliminated from further consideration.

Comment No. III.6

II.B The Proposed Limit for Natural Gas Consumption Is Not BACT for GHG Emissions from the DRI Facility

In Step 4 of the BACT analysis for GHG emissions, the draft PSD Permit concludes that natural gas consumption is the most relevant parameter that can be measured and that the minimization of natural gas consumed by the process is the most effective means of reducing GHG generation. As an evaluation, the draft PSD Permit quotes verbatim the following paragraph from Applicant's GHG BACT Analysis:

Historical rates of GHG emissions for the DRI process, measured using the unit metric of natural gas consumption per tonne of product has decreased over time as market forces have driven process efficiency. Early designs of the DRI process could be expected to meet an efficiency of 15 decatherrns of natural gas per tonne of DRI produced. This efficiency metric has gradually fallen over several years, until the current-day state of the art is expected to require no more than 13 decatherrns of natural gas per tonne DRI.

Neither the Applicant's GHG BACT Analysis nor the draft PSD Permit contains any documentation for this statement.

Based on this discussion, the draft PSD Permit in Step 5 of the BACT analysis for GHG emissions determines a numerical limit for the consumption of natural gas and discusses compliance with this limit for the Reformer/Main Flue Gas Stack (DRI-108/208):

Due to production rate and product quality variability in any production process, production rates should be inclusive of all production at the facility, both of regular and off-spec materials. Additionally, natural gas is consumed in the DRI process as both a raw material (for the formation of reducing gas) and as a fuel (for heating to reaction temperatures). All sources of natural gas consumption at the Reformer should be included in the analysis. BACT is no more than 13 decatherms of natural gas per tonne of DRI (11.79 MM Btu/ton of DRI). Compliance with the BACT limit shall be determined on the basis of total natural gas consumption, divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling average.

The draft Title V Permit implements this determination in the following condition for the Reformer/Main Flue Gas Stack in Train #1 of the DRI facility only (DRI-108):

Specific Requirement #81:

BACT is Natural [sic] gas \leq 13 MMBTU per Tonne [sic] of Direct Reduced Iron (DRI) produced. Compliance with the BACT limit shall be determined on the basis of total natural gas consumption, divided by total production (including regular and off-spec DRI product). Which Months: All Year, Statistical Basis: Twelve-month rolling average (rolling 1-month basis)

There are a number of problems with this proposed BACT determination. First, the limit for natural gas consumption for DRI production determined by the Applicant and the draft PSD is considerably higher than reported in the literature. Second, this limit is not supported by the values for natural gas consumption used by the Applicant for calculation of criteria pollutant emissions from the DRI facility. Third, the draft PSD Permit incorrectly identifies this limit not for the entire facility but rather only for the Reformer/Main Flue Gas Stack (DRI 108) in Train #1 of the DRI facility. Fifth,⁴⁸ the draft Title V Permit fails to state that this is a BACT limitation for GHG.

LDEQ Response to Comment No. III.6

Natural gas consumption of other DRI facilities is addressed in LDEQ Response to Comment No. III.7. The natural gas consumption reported by Nucor and used to calculate criteria pollutant emissions is addressed in LDEQ Response to Comment No. III.8. LDEQ Response to Comment No. III.9 addresses placement of the BACT limit in the PSD permit. Finally, the proposed Title V permit does identify the BACT limitation of 13 MM Btu/tonne of DRI produced (Specific Requirements 81 and 236). When read with PSD-LA-751, it is readily apparent that this limit was established to limit greenhouse gas (CO₂e) emissions. Nevertheless, LDEQ will note this fact in the Specific Requirements of the final Title V permit.

Comment No. III.7

II.B.1 Lower Natural Gas Consumption for DRI Production Is Reported in the Literature

As mentioned above, neither the Applicant's GHG BACT Analysis nor the draft PSD Permit contains any documentation for the conclusion that a consumption of 13 decatherms of natural gas per tonne of DRI produced is BACT for GHG emissions

⁴⁸ Note that only four problems are alleged.

from the DRI facility. Review of the literature shows that considerably lower values are reported for DRI processes for both other facilities and for DRI production processes. Table 2 below summarizes reported values for natural gas consumption as well as electricity consumption for specific DRI facilities in the U.S. and Australia and for several DRI production processes, including Midrex, HYL, and Finmet. (For comparison purposes, all reported values for natural gas consumption were converted to million British thermal units per tonne of DRI produced (“MMBtu/tonne DRI”).)

Table 2: Reported values for natural gas consumption and electricity consumption for DRI facilities

	DRI Process	Natural Gas Consumption (calculated)^a	Electricity Consumption
<i>Facility-specific (status)</i>			
Nucor DRI Facility, Convent, LA (<i>draft permits</i>) Capacity: 5.0x10 ⁶ tonnes DRI/year	n/a	13 decatherms/tonne DRI 13 MMBtu/tonne DRI	n/a
Austeel Pty Ltd, Cape Preston, Australia (<i>permitted</i>) Capacity: 5.6x10 ⁶ tonnes DRI/year ^b	Midrex	55,280 TJ/year (at capacity) (9.7 MMBtu/tonne DRI)	n/a
Essar Steel Minnesota, Nashwauk, MI (<i>under construction</i>) Capacity: 2.8x10 ⁶ tonnes DRI/year	Midrex ^c	8-9 MMBTU/ton DRI (7.3-8.2 MMBtu/tonne DRI)	n/a
<i>Process-specific</i>			
	HYL	2.25 to 2.3 Gcal / ton DRI (9.8-10.0 MMBtu/tonne DRI)	60 to 80 kWh/ton DRI
		10.7 million kJ / tonne DRI (10.1 MMBtu/tonne DRI)	90 kWh/tonne DRI
	Midrex	10.30 MMBtu/tonne DRI	130 kWh/tonne DRI
	HYL III ^d	11.33 MMBtu/tonne DRI	<i>n/a</i>
	Finmet ^e	11.55 MMBtu/tonne DRI	150 kWh/tonne DRI

Notes:

n/a not available

a calculated using the following conversion factors: 1 Btu = 1.055 J (at 59 F); 1 Btu ~ 252-253 cal (average 252.5 cal); 1 tonne = 1.1023 ton

b The facility produces DRI and hot briquetted iron (“HBI”), a compacted form of DRI designed for ease of shipping, handling, and storage; because there is no additional natural gas demand for the briquetting process of DRI, natural gas consumption figures for DRI and HBI are directly comparable

c Direct feed of DRI to electric arc furnace

d Proposed for use by Mineralogy Pty Ltd, Ausi Iron Project, Australia (capacity: 4x10⁶ tonnes HBI/year)

e Proposed for use by BHP Billiton, Boodarie, Australia

As shown in Table 2, the value of 13 decatherms (or MMBtu) of natural gas consumed per tonne of DRI produced determined by the Applicant and the draft PSD Permit as BACT is considerably higher than reported in the literature for other facilities and for the various DRI production processes which range from 7.3 to 11.55 MMBtu/tonne DRI produced.

The lowest value for natural gas consumption, 7.3-8.2 MMBtu/tonne DRI (8-9 MMBtu/ton DRI), was estimated for the Essar Minnesota Steel (formerly Minnesota Steel Industries, LLC) project at the former Butler Mine on the Mesabi iron ore range Minnesota. The facility is currently under construction and expected to be operational end of 2012. The facility will be the first fully-integrated mine through steel-making facility in North America and will produce about 3.1 million tons (2.8 million tonnes) per year of DRI (56 percent of the proposed Nucor DRI facility). The DRI process will use a Midrex shaft furnace and DRI product will be discharged directly to the electric arc furnace. Clearly, the proposed limit of 13 MMBtu/tonne DRI produced is not BACT for GHG emissions.

LDEQ Response to Comment No. III.7

With respect to the process-specific natural gas consumption rates, it is imperative that products of the same metallization and carbon content are being compared; this cannot be assessed with the information provided by the commenter. Nucor has informed LDEQ that one should expect a 2.5 percent increase in natural gas consumption per 1 percent increase in metallization and a 7 percent increase in natural gas consumption per 1 percent increase in carbon content. Thus, without knowing the product specifications associated with the published natural gas consumption rates, direct comparisons cannot be made.

Further, the references cited by the commenter provide no data to substantiate the performance claims are achievable over extended periods. Instead, they appear to use optimal “steady state” operation as the basis for the stated natural gas consumption rates and exclude off-spec product, startups, and shutdowns. Startups and shutdown events are part of normal operations and may occur as frequently as twice per week in order to adjust for different ores, natural gas compositions, and product quality needs of specific orders.

Moreover, it is not clear if the natural gas combustion rates are based on the net (or lower) heating value (LHV) of natural gas (which is quite common) or its gross (or higher) heating value (HHV). Natural gas will be monitored by Nucor based on its HHV. Use of the HHV accounts for all of the energy released during combustion, whereas use of LHV reflects the fact that some of the energy is lost as unrecoverable heat in the flue gas. In general, LHV is approximately 10 percent less than HHV.

EPA’s Environmental Appeals Board (EAB) has had occasion to address efficiency-related arguments in several past PSD cases and has acknowledged that permitting agencies have discretion in determining whether a particular control efficiency level is appropriate in determining BACT and in setting an appropriate emissions limit. The EAB has found that:

When [a permit issuer] prescribes an emissions limitation representing BACT, the limitation does not necessarily reflect the highest possible control efficiency achievable by the technology on which the emissions limitation is based. Rather, the [permit issuer] has discretion to base the emissions limitation on a control efficiency that is somewhat lower than the optimal level. * * * There are several different reasons why a permitting authority might choose to do this. One reason is that the control efficiency achievable through the use of the technology may fluctuate, so that it would not always achieve its optimal control efficiency. * * * Another possible reason is that the technology itself, or its application to the type of facility in question, may be relatively unproven. * * * To account for these possibilities, a permitting authority must be allowed a certain degree of discretion

to set the emissions limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the permittee to achieve compliance consistently.⁴⁹

In the same decision, the EAB also stated that:

In essence, Agency [EPA] guidance and our prior decisions recognize a distinction between, on the one hand, measured “emissions rates,” which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the “emissions limitation” determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility’s life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the “emissions limitation” that is “achievable” for that pollution control method over the life of the facility. **Accordingly, because the “emissions limitation” is applicable for the facility’s life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term. Thus, the permit issuer may take into account the absence of long term data,** or the unproven long-term effectiveness of the technology, **in setting the emissions limitation that is BACT for the facility.** *Masonite*, 5 E.A.D. at 560 (noting that the permit issuer must have flexibility when “the technology itself, or its application to the type of facility in question, may be relatively unproven”).

(Emphasis added).

PSD-LA-751 establishes a federally enforceable process efficiency standard in order to limit GHG emissions; this limit is likely the first of its kind.

Finally, the HYL process was considered by Nucor and may result in fewer emissions of greenhouse gases; however, this “process is still experimental and has never been attempted at a DRI facility of the size that Nucor is considering.”⁵⁰ Nevertheless, Nucor may pursue development of this process at a later date.

Comment No. III.8

II.B.2 The Sum of Values for Natural Gas Consumption Used by the Applicant for Calculation of Criteria Pollutant Emissions from the DRI Facility Is Less Than Half the Proposed BACT Limit

In the calculations of criteria pollutant emissions from the DRI facility, the Applicant used the following maximum (average) firing rates per DRI train:

Reformer/Main Flue Gas Stack (DRI-108/208):	1,597 (1,521) MMBtu/hour
Package Boiler (DRI 109/209):	290 (220) MMBtu/hour
Hot Flare (DRI-110/210) pilot:	160 (149) scf/hour

⁴⁹ In re: Newmont Nevada Energy Investment, L.L.C., TS Power Plant, PSD Appeal No. 05-04, December 21, 2005, pg. 43.

⁵⁰IT Questions Response, Section 7.1.2 (EDMS Doc ID 7731649)

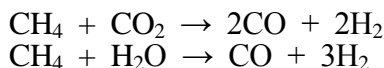
Based on the maximum annual hours of operation for the Reformer/Main Flue Gas Stack (DRI-108/208) and the Package Boiler (DRI 109/209) (8,000 hours/year) and the Hot Flare pilot (8,760 hours/year) and a higher heating value for natural gas of 1,020 British thermal units per standard cubic foot (“MMBtu/scf”), the annual natural gas consumption on a per-unit-basis can be estimated as follows:

Reformer/Main Flue Gas Stack (DRI-108/208):	1.28×10^7 (1.22×10^7) MMBtu/year
Package Boiler (DRI 109/209):	2.32×10^6 (1.76×10^6) MMBtu/year
Hot Flare (DRI-110/210) pilot:	1.46×10^3 (1.33×10^3) MMBtu/year

Therefore, total annual natural gas consumption for both trains of the DRI facility can be estimated at 3.02×10^7 MMBtu/year (2.79×10^7 MMBtu/year). Based on the maximum annual production of 5.0 million tons of DRI per year for both trains of the DRI facility, natural gas consumption on a per unit basis can be estimated at 6.0 (5.6) MMBtu/tonne of DRI, less than half the value of 13 MMBtu/tonne DRI determined to be BACT by the Applicant and the draft PSD Permit. Thus, unless there are other major natural gas-consuming processes that the draft permits did not disclose, BACT for natural gas consumption as a parameter for GHG emissions for the facility is no more than 6.0 MMBtu/tonne of DRI.

LDEQ Response to Comment No. III.8

The commenter has not accounted for the fact that natural gas is not only used as a fuel, but also to generate reducing gas. At elevated temperatures, natural gas dissociates into a reducing gas rich in carbon monoxide and hydrogen, which are the primary reductants for the process.



Comment No. III.9

II.B.3 Draft Title V Permit Specific Requirements #81 and #82 for Natural Gas Consumption Are Meaningless and Must Be Revised and/or Replaced by Facility-wide Requirements

Presumably to implement the BACT determinations for GHGs, the draft Title V Permit contains the following two conditions for the Reformer / Main Flue Gas Stack (DRI-108/208):

Specific Requirement #81:

BACT is Natural [sic] gas ≤ 13 MMBTU per Tonne [sic] of Direct Reduced Iron (DRI) produced. Compliance with the BACT limit shall be determined on the basis of total natural gas consumption, divided by total production (including regular and off-spec DRI product). Which Months: All Year, Statistical Basis: Twelve-month rolling average (rolling 1 month basis)

Specific Requirement #82:

DRI production rates and natural gas consumption shall be tracked using both the fuel consumption tracking method of Subpart C, as well as Subpart Q for iron and steelmaking from the promulgated Mandatory Reporting of Greenhouse Gas rule. The mass balance approach should consider the carbon inbound with the natural gas, as well as outbound carbon in the DRI product.

During the Technical Review of the draft Title V permit for the DRI facility, the Applicant commented that two Specific Requirements pertaining to BACT for CO₂ would more appropriately be listed under the facility-wide requirements. In response LDEQ argues that “BACT limits are on a per emission source basis (DRI unit), and need to be met for each process unit. Averaging these parameters would not satisfy BACT.” LDEQ’s statement and its implementation of natural gas consumption as a BACT limit for GHGs are problematic for several reasons.

First, in the face of this explicit statement requiring BACT on a per emission source (or unit) basis, LDEQ proceeds to include in the draft Title V Permit only two Specific Requirements (#81 and #82) to implement GHG BACT for the Reformer / Main Flue Gas Stack at the DRI train 1 (DRI-108) and fails to include any Specific Requirements for the Reformer / Main Flue Gas Stack at the DRI train 2 (DRI-208) or the Package Boiler (DRI-109/209) and the Acid Gas Absorption Vent (“DRI-111/211) which were previously identified as emissions units subject to BACT for GHGs.

Second, the limit for natural gas consumption of ≤ 13 MMBtu per tonne of DRI produced in Specific Requirement #81 originates in the Applicant’s GHG BACT Analysis (13 decatherms of natural gas per tonne DRI produced) and was determined for the entire DRI process, *i.e.* on a facility-wide basis. Thus, this limit cannot be used for the Reformer/Main Flue Gas Stack at the DRI train 1 (DRI-108) without determining the portion of natural gas consumed by this particular emissions unit. As there are two DRI trains as well as several other units that consume natural gas (package boilers, flare pilot), the proposed limit of ≤ 13 MMBtu of natural gas per tonne of DRI produced is too large by a factor of more than two. Further a limit on natural gas consumption at the Reformer / Main Flue Gas Stack at the DRI train 1 (DRI-108) would require monitoring of the natural gas consumption at this unit; the draft permits contain no such condition. Thus, as written, Specific Requirement #82 is meaningless.

Third, any limit on natural gas consumption as a parameter for GHG BACT must be accompanied by specifications of the natural gas (*e.g.*, carbon content, higher heating value) used to determine the fuel consumption determined as BACT for GHGs as well as a condition for either adequate monitoring procedures to determine these specifications or a condition requiring that only fuel be used that meets the specifications used to calculate BACT emission limits on natural gas consumption. Otherwise the limit is meaningless. The permits contain no such conditions.

Fourth, Specific Requirement #82 requires tracking of DRI production rates and natural gas consumption “using both the fuel consumption tracking method of Subpart C, as well as mass balance approach similar to Subpart Q for iron and steelmaking from the promulgated Mandatory Reporting of Greenhouse Gas rule.” This condition is inadequate and unenforceable because the procedures laid out in the Mandatory Reporting of Greenhouse Gas rule are not applicable to determine either the DRI production rates or natural gas consumption. For example, Subsection C of the Mandatory Reporting of Greenhouse Gas rule lays out a procedure for determining GHG emissions based on fuel consumption of various fuels rather than a fuel consumption tracking method for natural gas. Similarly, Subsection Q of the Mandatory Reporting of Greenhouse Gas rule does not provide a mass balance approach for determining DRI production rates or natural gas

consumption but rather a procedure to determine GHG emissions from various processes in the iron and steel production (*e.g.*, taconite indurating furnaces, sinter processes, electric arc furnaces, etc.).

Neither requirement is specific enough to enforce BACT requirements for the facility. For example, Subpart C of the Mandatory Reporting of Greenhouse Gas rule relies on default CO₂ emission factors which do not satisfy the need for source specific monitoring; for pipeline natural gas the weighted U.S. average is used. Because the carbon content and higher heating value, and, thus, the specific carbon emission coefficient, can vary considerably for pipeline-grade natural gas in space and time (*see* Comment II.C), the use of a default value is not sufficient to assure that facility-specific BACT requirements for GHGs are met. Further, the requirement for the mass balance approach to “consider the carbon inbound with the natural gas, as well as outbound carbon in the DRI product” is vague and not define by a calculation procedure. Finally, the requirement to follow a “mass balance approach similar to...” leaves the door wide open to interpretation and, thus, fails to assure that facility-specific BACT requirements for GHGs are met. The draft PSD Permit must clearly specify the procedure for making the mass balance calculations.

Fifth, LDEQ’s position regarding facility-wide BACT applicability is contradicted by EPA’s guidance on the matter. For example, the EPA recently clarified the scope of the entity or equipment to which a top-down BACT analysis is applied based on 42 USC § 7479(1) and (3); 40 CFR § 52.21(b)(1) and (5):

“EPA has generally recommended that permit applicants and permitting authorities conduct a separate BACT analysis for each emissions unit at a facility and has also encouraged applicants and permitting authorities to consider logical groupings of emissions units as appropriate on a case-by-case basis. For new sources triggering PSD review, the CAA and EPA rules provide discretion for permitting authorities to evaluate BACT on a facility-wide basis by taking into account operations and equipment which affect the environmental performance of the overall facility. *The term “facility” and “source” used in applicable provisions of the CAA and EPA rules encompass the entire facility and are not limited to individual emissions units.*”

The Applicant has determined natural gas consumption for the Reformer / Main Flue Gas Stack (DRI-108/208), the Package Boiler (DRI-109/209), and the Hot Flare (DRI-110/210).

Accordingly, LDEQ should revise the draft PSD Permit and draft Title V Permit to include limits for natural gas consumption on a unit-specific basis and/or include a facility-wide limit. All limits must be accompanied by adequate compliance monitoring and reporting requirements.

LDEQ Response to Comment No. III.9

The BACT limit established by PSD-LA-751 for GHG emissions is 13 MM Btu (*i.e.*, decatherms) per metric ton (or tonne) of DRI produced. It accounts for the natural gas consumed by all combustion sources at the facility, including the reformers, package boilers, and hot flares, as well as the natural gas used as a reactant in the reducing furnace, inclusive of all startup/shutdown emissions and off-spec production. LDEQ agrees that the BACT limit would be more appropriately attributed the entire facility (and thus placed under UNF 0002 in Permit No. 3086-V0). The permit will be modified accordingly.

It is important to understand the monitoring provisions associated with the BACT limit need not require quantification of CO₂ emissions from the facility – that is the role of the Mandatory Greenhouse Gas Reporting rule under 40 CFR 98. Therefore, performing a mass balance calculation, and thus monitoring parameters such as carbon content of the natural gas and DRI product, is not necessary. Instead, the monitoring provisions must be designed to verify compliance with the 13 MM Btu/tonne DRI BACT limit. As such, the amount of natural gas consumed by the process, including its heating value, and the amount of DRI product produced are the only necessary parameters. Therefore, Specific Requirements 82 and 235 in proposed Permit No. 3086-V0 will be deleted and replaced with the following specific requirements under UNF 0002:

- BACT for greenhouse gas (CO₂e) emissions: Monitor the total DRI facility natural gas and energy consumption monthly by maintaining a master flow meter that totals natural gas consumed by the DRI process. Conversion from natural gas volume to energy consumption shall be based on the natural gas analysis provided by the supplier, or direct sampling by the facility, for the same month and reflect the HHV of the gas. [LAC 33:III.509]
- BACT for greenhouse gas (CO₂e) emissions: Retain monthly records of total DRI facility natural gas and energy consumption, in decatherms. Maintain these records for a period of at least five years. [LAC 33:III.509]
- BACT for greenhouse gas (CO₂e) emissions: Maintain monthly records of total DRI production from the reduction furnace, inclusive of off-spec material and captured DRI dust, in metric tons produced. Maintain these records for a period of at least five years. [LAC 33:III.509]
- BACT for greenhouse gas (CO₂e) emissions: Determine compliance with the GHG BACT limitation of 13 decatherms per metric ton of DRI by maintaining a trailing twelve-month rolling average of natural gas consumption less than or equal to 13 decatherms per metric ton of DRI. The rolling average shall be calculated from the records of actual natural gas consumption and actual DRI production required by this permit. Maintain records of the rolling average for a period of at least five years. [LAC 33:III.509]

Finally, the guidance cited by the commenter is supportive of LDEQ's facility-wide BACT determination for GHGs. EPA's "PSD and Title V Permitting Guidance For Greenhouse Gases" states that:

For new sources triggering PSD review, the CAA and **EPA rules provide discretion for permitting authorities to evaluate BACT on a facility-wide basis** by taking into account operations and equipment which affect the environmental performance of the overall facility. The term "facility" and "source" used in applicable provisions of the CAA and EPA rules encompass the entire facility and are not limited to individual emissions units.⁵¹

(Emphasis added.)

Comment No. III.10

⁵¹ "PSD and Title V Permitting Guidance For Greenhouse Gases", pg. 24

II.C The Draft PSD Permit Must Specify the Procedures for Estimating GHG Emissions

As mentioned above, the draft PSD Permit must clearly specify the procedure for making the mass balance calculation for carbon in the DRI production process. Specific Requirement #82, which requires calculating DRI production rates and natural gas consumption “using both the fuel consumption tracking method of Subpart C, as well as Subpart Q for iron and steelmaking from the promulgated Mandatory Reporting of Greenhouse Gas rule” is not adequate.

Subpart Q for iron and steelmaking from the promulgated Mandatory Reporting of Greenhouse Gas rule does not provide a calculation procedure for DRI production and the reference is therefore moot. Therefore, the LDEQ must develop a calculation procedure for DRI production and present it for public review.

This calculation procedure must account for the fact that the carbon content and heating values of pipeline-grade natural gas can show considerable variation over space and time, as shown in Figure 1.⁵²

The U.S. Department of Energy (“DoE”) reports CO₂ fuel efficiency coefficients for pipeline natural gas ranging from 54.01 kg CO₂/MMBtu (5.401 kg CO₂/therm) at a higher heating value (“HHV”) of 975-1,000 BTU per cubic foot (“Btu/scf”) of natural gas to 53.72 kg CO₂/MMBtu (5.372 kg CO₂/therm) at an HHV of 1,075-1,100 Btu/scf. Given this variability in fuel composition, facility-specific values for carbon content and heating value should be used to determine GHG emissions from natural gas combustion wherever possible. This information should be available from suppliers or Material Data Safety Sheets for the purchased fuel and should be confirmed with fuel analysis results.

LDEQ Response to Comment No. III.10

See LDEQ Response to Comment No. III.9.

Comment No. III.11

II.D. The Draft Permits Fail to Address GHG Emissions from the Pig Iron Plant

Based on our discussion, it is my understanding that the pig iron and DRI manufacturing plants must be permitted under a single PSD permit, and the public must be given an opportunity to review and comment on the aggregate emissions and air quality impacts from the pig iron and DRI manufacturing processes, pursuant to § 165 of the Act.

LDEQ did not provide any discussion of GHG emissions from the pig iron plant in the proposed permits for the DRI facility and the previously issued permit for the pig iron plant did not include a BACT analysis or BACT limits for GHG emissions. Thus, the aggregate emissions from both facilities have not been evaluated and BACT limits for the pig iron plant have not been developed and implemented in enforceable conditions.

⁵² For Figure 1, see EDMS Doc ID 7781463 (pg. 24)

Energy requirements for pig iron production have been estimated at 12.2 MMBtu/tonne (13.5 MMBtu/ton) of liquid pig iron and 10.4 MMBtu/tonne (11.5 MMBtu/ton) for pig iron nuggets depending upon ore type, reformer, etc. Considering the substantially higher energy requirements compared to DRI production, LDEQ should evaluate substituting the pig iron portion of the facility with DRI production as an alternative control option. (*See* discussion in Comment II.A.1.)

LDEQ Response to Comment No. III.11

See LDEQ Response to Comment No. II.2.

IV. Responses to Comments Submitted by Nucor Corporation (by Kean Miller) dated January 3, 2010

Comment No. IV.1

The PSD permit for the DRI plant will not be issued until after January 2, 2011, and other commenters have indicated that the permit may be subject to the requirement to include BACT for greenhouse gases (GHG) due to the EPA “PSD Tailoring Rule.”

As set forth in Section 1 of these comments, the proposed DRI production process set forth in NS-LA’s application is an innovative, energy efficient iron making method. Use of the permitted equipment to manufacture DRI will satisfy the GHG BACT requirements in any event, should those requirements be deemed relevant.

LDEQ Response to Comment No. IV.1

LDEQ’s BACT determination for greenhouse gases (GHGs) is set forth in Permit Nos. 3086-V0 and PSD-LA-751.

Comment No. IV.2

Requirement for Additional NOx Control For Certain Pig Iron plant Emission Units

Nucor objects to the requirements for NOx control for the following sources at the Pig Iron plant: Coke Oven Main Flue Stacks (COK-111 and COK-211 grouped as RLP 0006 and RLP0012); Sinter Plant (SIN-I01, EQT0031); Hot Blast Stoves (STV-101, RLP0015); Power Boilers (PWR-101, PWR-102, PWR-103, PWR-104 grouped under CRG002); and Pulverized Coal Injection Mill (PCi-101, RLP0013). These NOx control requirements were imposed solely due to the enactment of a 1-hour National Ambient Air Quality Standard for NOx by EPA, effective in April 2010. That NAAQS is under litigation and may be overturned. For this reason, and the additional reasons discussed below, Nucor believes it is premature for LDEQ and/or EPA to impose such control requirements. Each of the sources above is being required to add Selective Catalytic Reduction (“SCR”) as add on control technology to reduce NOx emissions below those levels which were permitted in the May 2010 permits. Nucor requests that the original NOx control requirements and emission rate limits for these sources in the May 2010 permits be maintained in both the PSD and Title V permits for the Pig Iron plant. For this reason, the requirements of the following Specific Requirements in the Title V permit

for the Pig Iron plant should also be revised: SR 237, SR265, SR343, SR 670, SR 671, SR 783, SR 802.

NS-LA has proposed to add additional NO_x control technology to the modified pig iron plant permit solely because LDEQ indicated that EPA would object to the Pig Iron plant permits if NS-LA did not demonstrate that the modified Pig Iron plant and DRI plant would comply with a newly-promulgated one-hour nitrogen oxide (“NO_x”) National Ambient Air Quality Standard (“NAAQS”). Nucor objects to any requirement to demonstrate compliance with this new standard. The one-hour NO_x standard has not yet become applicable to stationary sources in Louisiana because EPA has not yet issued a state implementation plan (SIP) call for it, as is required pursuant to Section 110(a)(1) of the Clean Air Act, 42 U.S.C. §7410(a)(1). Furthermore, there has been no EPA-approved revision to the Louisiana State Implementation Plan (SIP) to implement a one-hour NO_x standard in Louisiana. Moreover, as indicated above, the 1-hour NO₂ NAAQS is under litigation and is subject to being overturned. In the present circumstances it is up to LDEQ, rather than EPA, to decide how to evaluate compliance with the one-hour NO_x standard.

LDEQ and EPA’s requirement that the NS-LA pig iron facility demonstrate it will comply with NAAQS that have not yet become effective by virtue of implementation through a revised SIP is unlawful. This requirement subjects the pig iron manufacturing facility to significant additional capital and operating costs. EPA’s insistence that the NS-LA pig iron plant permit application satisfy, and that LDEQ impose on NS-LA, NAAQS that have not yet become effective in a Louisiana State Implementation Plan revision approved by EPA exceeds the statutory authority of both agencies. While Nucor understands that LDEQ imposed this requirement at the direction of EPA, Nucor believes such imposition constitutes an abuse of discretion by them. In short, the EPA and LDEQ will be acting arbitrarily, capriciously, and unlawfully if they ignore the clear mandates of the Clean Air Act to implement NAAQS requirements only through the statutory SIP enactment and approval process.

EPA imposed a number of requirements upon LDEQ which delayed it from taking timely action to issue the NS-LA Pig Iron plant permit within one year of receiving a completed application. For example, by repeatedly asserting and then changing demands on modeling the pig iron plant for compliance with the PM_{2.5} NAAQS, EPA substantially delayed the issuance of the Pig Iron plant permits.

EPA filed comments in respect to the proposed Pig Iron plant facility on December 1, 2008. Among other things, EPA suggested that LDEQ exercise discretion to require NS-LA to consider alternative manufacturing processes, such as building a DRI plant, as part of making a BACT determination for the PSD permit. In addition, EPA said that the initial modeling that LDEQ relied upon to publish the public notice for the blast furnace facility permits “did not account for all maintenance scenarios with respect to increment and impacts on ambient air quality.” EPA noted that “on November 17, 2008, [NS-LA] committed to providing revised Class I and II modeling to LDEQ, EPA Region 6, and U.S. Fish and Wildlife Service (FWS).” EPA said that it was unable to determine at that time whether the proposed pig iron facility would have an adverse impact on NAAQS of PSD Class I and II increments, and would complete its modeling review after the revised modeling was submitted. Finally, EPA determined:

Since the original modeling used to support the proposed permit at public comment was incomplete, EPA strongly recommends a new comment for FWS,

EPA, and the public to evaluate the new modeling analysis that will be provided to LDEQ, the revised air permit application, and the preliminary determination.

To satisfy EPA, LDEQ issued another public notice and draft permit on March 3, 2010. It held a second public hearing on April 15, 2010. On May 24, 2010, LDEQ issued both PSD and a Title V permits for construction and operation of the Pig Iron plant. Ultimately, EPA accepted modeling performed for the PM_{2.5} NAAQS. However, EPA verbally indicated to LDEQ that it was prepared to place new requirements upon the permitting process in addition to PM_{2.5}. [sic]

On August 20, 2010, in response to changed business conditions, Nucor submitted an initial Part 70 and PSD permit application for two new 2.5 Million ton per year DRI process units at the facility. These operations are distinctly different from the currently-permitted project. They use different raw materials, make a different type of iron raw material, and do not share operating units with one another. Nucor also submitted an application for a minor modification to the existing Part 70 and PSD permit for the blast furnace operations to propose elimination of certain equipment from the facility, resulting in an overall reduction in emissions from the combined facilities. EPA's response was, through LDEQ, to tell NS-LA that it was required to modeling [sic] both facilities to demonstrate compliance with the new one-hour NO₂ NAAQS at the fenceline.

Modeling of the NO_x emissions from the DRI plant alone shows that such emissions are below the PSD Significant Impact Level for the new 1-hour NAAQS. Had the Pig Iron plant already been constructed, it would be clear that no further review for the new 1-hour NAAQS would have been required under the PSD program, state or federal. Due to the permitting delays associated with the Pig Iron facility, such construction had not been undertaken.

More fundamentally, however, EPA's policy that PSD construction permit applications for new projects must demonstrate compliance with a NAAQS under EPA rules and guidance that have yet to be incorporated into a permitting state's Clean Air Act SIP is contrary to the plain language and structure of the Clean Air Act. See CAA §§107, 110, 42 U.S.C. §§ 7407, 7410. Neither the NAAQS for PM_{2.5} nor the NAAQS for one-hour NO_x have been incorporated into the Louisiana SIP by a revision to the SIP on which the public has had an opportunity to comment, and which the EPA has approved. Therefore, EPA's insistence that the Pig Iron plant air quality analysis demonstrate compliance with this new standard, and LDEQ's acquiescence in the EPA demand, are in excess of each agency's respective statutory authority, arbitrary and capricious, and inconsistent with the express language of the Clean Air Act and the Louisiana Environmental Quality Act. LDEQ should exercise its own discretion in determining what technology is necessary to demonstrate compliance with a NAAQS.

EPA promulgated the 1-hour NO_x NAAQS on February 9, 2010, effective April 12, 2010. EPA did not release its central agency memoranda on modeling compliance the NO_x NAAQS until June 28, 2010, after LDEQ had issued the initial NS-LA permits for the Pig Iron plants. EPA did not indicate until September 2010 that Nucor must now perform cumulative modeling (modeling of the proposed DRI plant together with the Pig Iron plant) for demonstrating compliance with the 1 hour NO_x NAAQS.

Modeling protocols for the new 1-hour standard are yet to be developed and approved. And, to reiterate —the standard itself is under litigation. Modeling requires use of conservative, worst case or near worst case scenarios. In order for the combined facilities

to demonstrate compliance with that standard under the cumulative modeling, NS-LA was required to eliminate the Heat Recovery Steam Generator bypass events by installing a redundant unit, and to install selective catalytic reduction (SCR) NO_x control technology on the coke oven main flue stacks, sinter plant, hot blast stoves, power boilers and pulverized coal injection mill. Collectively, these modifications will cost Nucor millions of extra dollars.

The EPA Region 6 comments, threats, and directives to LDEQ and Nucor requiring demonstrations of compliance with just-promulgated NAAQS revisions are based on nothing more than what the agency calls its “existing interpretation” of the Clean Air Act and of EPA regulations, and its “position on how these regulations apply under the federal PSD program.” This EPA “position,” as NS-LA understands it, has two parts: First, that §165(a)(3) of the Clean Air Act, 42 U.S.C. §7475(a)(3), and 40 CFR 52.21(k)(1) require applicants for PSD permits to demonstrate that their projects will comply with all NAAQS standards that are “in effect” at the time the permit is to be issued. Second, EPA purports that a NAAQS standard is “in effect” for purposes of the PSD program as of the effective date that EPA gives the standard in the Federal Register for purposes of starting the 60-day deadline for appealing it in the U.S. Court of Appeals for the D.C. Circuit.

EPA’s “interpretation” requiring a project to demonstrate immediate compliance with a just-revised NAAQS standard to issue a PSD permit refers to §165(a)(3) of the Act, but it ignores the Act’s explicit instruction on about how a NAAQS revision, like the 1-hour standard, is to be implemented. EPA correctly observes that §165(a)(3)(B) requires an applicant for a PSD permit to demonstrate that emissions from construction or operation of the facility to be permitted “will not cause, or contribute to, air pollution in excess of any ... national ambient air quality standard in any air quality control region ...” However, EPA’s “position” and “interpretation” ignore what Section 110 says about the process for implementing NAAQS revisions promulgated by EPA in the air quality control regions which are located in the states. Clean Air Act Section 107 requires states to establish “air quality control regions” within their respective borders and to submit them for EPA approval. Section 107 further says each state “shall have primary responsibility for assuring air quality within the entire geographic area comprising such state by submitting an implementation plan for such state which will specify the manner in which national primary and secondary ambient air quality standards will be achieved and maintained within each air quality control region in such state.” See 42 U.S.C. §7407(a). In addition, section 110(a)(1) of the Act, 42 U.S.C. §7410(a)(1) says that when EPA promulgates (or revises) a NAAQS for any air pollutant, each state must (within 3 years or such shorter period as EPA specifies), and “after reasonable notice and public hearings,” submit for EPA approval its plan for implementation, maintenance and enforcement of the revised NAAQS for that air pollutant in “each air quality control region (or portion thereof) within such state.” If a state fails to submit an approvable plan or plan revision, EPA may impose, but only after notice and comment rule making, federal plan requirements that will apply until the state corrects the deficiency. 42 U.S.C. §§110(c), 307(d)(1)(B). As regards the question of how and when a revised NAAQS becomes effective, Section 110(i) states that “[e]xcept for ... a plan promulgation under subsection (c) of this section, or a plan revision under subsection (a)(3) of this section, ... no action modifying any requirement of an applicable implementation plan may be taken with respect to any stationary source by the State or by the [EPA] Administrator.” 42 U.S.C. §7410(i). Thus, the Clean Air Act does not provide EPA power to declare a revised NAAQS standard, such as the one-hour NO_x standard, to be effective as to stationary sources upon final publication in the Federal

Register. Rather, revised NAAQS become effective only through a state taking action to implement them pursuant to the SIP revision process.

It is not difficult to understand why Congress established this procedure. Public hearings should be required to explain the costs, impacts and health benefits of a NAAQS revision as part of the process of implementing it in a state. This is particularly the case where implementing a revised NAAQS will have significant economic consequences in a state. This will certainly be so for the one-hour NO_x standard. EPA has determined that existing major sources, such as coal-fired and natural gas-fired power plants, are modeling potential violations of the new NO_x NAAQS. See, “Guidance concerning the implementation of the 1-hour NO_x NAAQS for the Prevention of Significant Deterioration Program” June 29, 2010.

EPA’s “interpretation” that the Nucor pig iron plant must model compliance with the one-hour NO_x standard as of the date it was published, and its threat to object to Nucor’s permit unless it did so, has had significant economic consequences for the project. Nucor was required to modify the project and its air permit to require installation of additional control technologies to control NO_x emissions from the coke ovens that remain in the project. These new emission controls are extremely expensive to install and operate, and push against the outermost technical limits of the control technologies involved.

Even though a completed permit application for the project was filed with LDEQ in May, 2008, and even though Section 165(c) of the Clean Air Act required the permit application to be granted within one year of that date, EPA has repeatedly delayed the project, and now insists that it demonstrate compliance with NAAQS that it did not issue until April 2010.

Nucor regards EPA’s repeated actions to delay LDEQ’s issuance of the initial permit and insistence that Nucor demonstrate compliance with newly-promulgated NAAQS standards to be in violation of the Clean Air Act, arbitrary and capricious, and in excess of its authority. Nucor objects to any permit condition requiring NS-LA to install control technology necessary to meet NAAQS that were first promulgated nearly two years after it filed a complete permit application, and one year after EPA was required to act on the permit. If not for the repeated delays in issuing a permit for this project (all caused by EPA Region 6’s insistence on running different modeling protocols in 2008 and 2009 to demonstrate compliance with the NAAQS for PM_{2.5} for which Louisiana has as yet submitted no plan revision) the NO_x and SO_x one hour limits would not have been applicable to this project even under EPA’s interpretation.

Nucor did not propose Selective Catalytic Reduction NO_x controls for the pig iron plant modification in response to comments that such controls were required in order to demonstrate BACT. To the contrary, SCR is beyond BACT and represents lowest achievable emissions rate technology for these types of units. The controls were added because of the requirement to perform an air quality analysis which will model compliance with one-hour NO_x standards when the modified pig iron plant and DRI plant are operating simultaneously and at full capacity. In short, this SCR control technology was necessary to model compliance with the one-hour NO_x NAAQS.

For the reasons stated above, Nucor requests that the requirement to install SCR on the Pig Iron emissions units indicated above, and associated emission rate limits and specific requirements be removed from the permit and the original NO_x BACT based limits and specific requirements be restored.

LDEQ Response to Comment No. IV.2

LDEQ recognizes that the need for selective catalytic reduction (SCR) controls and a supplementary heat recovery steam generator (HRSG) did not stem from LDEQ's BACT determinations set forth in PSD-LA-740.

LDEQ also shares Nucor's concerns regarding EPA's implementation of the 1-hour NO₂ National Ambient Air Quality Standard (NAAQS). By letter dated November 17, 2010, LDEQ urged EPA to consider an "alternative, temporary program" to "provide a reprieve from any requirement for modeling of 1-hour NO₂ concentrations." EPA responded on December 28, 2010, noting:

The June 29, 2010 NO₂ NSR implementation guidance memorandum to which you [LDEQ] made reference was our initial effort to provide states and permit applicants with information to assist in the permitting of new and modified sources of nitrogen oxide (NO_x). Our objective was to provide timely assistance, based on existing policy, for addressing implementation issues that have emerged associated with the 1-hour NO₂ NAAQS. At the same time, we recognized that additional guidance would be needed. We are currently developing more comprehensive guidance that will address additional issues that have arisen during the past months, and will likely involve the reassessment of existing policy and the consideration of new rulemaking where appropriate the more fully address those implementation issues.

Our plan is to consult with technical staff in the state and local air agencies before we issue the guidance early in 2011. With regard to your recommendation that we delay for two years the prevention of significant deterioration (PSD) modeling requirements for demonstrating new source compliance with the 1-hour NO₂ NAAQS, you may be aware that we are currently being petitioned by the American Petroleum Institute on this particular issue. Accordingly, we are carefully evaluating our options for addressing this concern. My primary objective is to ensure the protection of public health afforded by the new 1-hour NO₂ NAAQS, while also providing the necessary implementation guidance so that the permitting process can proceed in an environmentally and economically sound manner.

In requiring Nucor to comply with the 1-hour NAAQS for NO₂, LDEQ looked to EPA's April 1, 2010, memorandum entitled "Applicability of the Federal Prevention of Significant Deterioration Permit Requirements to New and Revised National Ambient Air Quality Standards." According to this document:

EPA generally interprets the CAA and EPA's permitting program regulations to require that each final PSD permit decision reflect consideration of any NAAQS that is in effect at the time the permitting authority issues a final permit.

Accordingly, permits issued under 40 CFR 52.21 on or after April 12, 2010, must contain a demonstration that the source's allowable emissions will not cause or contribute to a violation of the new 1-hour NO₂ NAAQS.

Also, LDEQ reviewed EPA's "Primary National Ambient Air Quality Standards for Nitrogen Dioxide," promulgated on February 9, 2010.⁵³ The final rule acknowledges that:

⁵³ 75 FR 6474

SIPs that address the PSD requirements related to attainment areas are due no later than 3 years after the promulgation of a revised NAAQS for NO₂.⁵⁴

However, it goes on the state that:

First, major new and modified sources applying for NSR/PSD permits will initially be required to demonstrate that their proposed emissions increases of NO_x will not cause or contribute to a violation of either the annual or 1-hour NO₂ NAAQS and the annual PSD increment.⁵⁵

Finally, LDEQ consulted EPA's draft 1990 New Source Review Workshop Manual. According to the manual:

Once energy, environmental, and economic impacts have been considered, BACT can only be made more stringent by other considerations outside the normal scope of the BACT analysis as discussed under the above steps. **Examples include cases where BACT does not produce a degree of control stringent enough to prevent exceedances of a national ambient air quality standard or PSD increment, or where the State or local agency will not accept the level of control selected as BACT and requires more stringent controls to preserve a greater amount of the available increment. A permit cannot be issued to a source that would cause or contribute to such a violation, regardless of the outcome of the BACT analysis.**⁵⁶

(Emphasis added.)

LDEQ is aware that the 1-hour NO₂ NAAQS is being litigated. Should the standard be vacated, LDEQ will reevaluate the appropriateness of the SCR controls and supplementary HRSG. Further, LDEQ will reconsider these permit conditions should EPA's "more comprehensive guidance" and "reassessment of existing policy" suggest that compliance with the 1-hour NO₂ NAAQS need not be demonstrated prior to adoption of the standard by the state or EPA's approval of Louisiana's PSD State Implementation Plan (SIP) described in the final 1-hour NO₂ NAAQS rulemaking.

Comment No. IV.3

Comments Respecting Opposition by Zen-Noh Grain Corporation

Issuance of the pig iron plant permits was the culmination of a more than two-year permitting process, a process that was overextended in large part due to the efforts of Zen-Noh Grain Corporation ("Zen-Noh"), a subsidiary of a Japanese agricultural cooperative. Zen-Noh has repeatedly attempted to use the permitting process to block any development or job creation associated with the Nucor property. Zen-Noh appealed LDEQ's granting of the Pig Iron plant permits in Louisiana state court, and filed petitions to the EPA seeking its objection to those permits. In addition, Zen-Noh filed a federal court lawsuit against LDEQ in 2009 seeking to enjoin LDEQ's efforts

⁵⁴ 75 FR 6524

⁵⁵ 75 FR 6525

⁵⁶ Pg. B.54

even before LDEQ issued the permits. (The EPA has thus far declined to object to the permits and the U.S. District Court for the Eastern District of Louisiana dismissed Zen-Noh's suit noting that there was no jurisdiction for Zen-Noh to bring the action.) At present, Zen-Noh has filed its second federal lawsuit seeking to derail the ongoing permitting process, this one against EPA for its failure to act on Zen-Noh's petition that EPA object to the May 24, 2010 permits. The LDEQ should be aware that Zen-Noh has ulterior business motives that underlie the frivolous environmental arguments it has raised in these proceedings.

Issuance of these construction and operating permits has been consistently and vociferously opposed by Zen-Noh, which owns property abutting the proposed NS-LA facilities. Zen-Noh is a Japanese-owned grain export terminal. Although Nucor acknowledges Zen-Noh's right to make public comments, it has submitted numerous, redundant and misleading comments regarding the Pig Iron plant for an improper purpose: to clutter the administrative record and slow LDEQ's and to slow LDEQ's [*sic*] process by making it respond to the same comments-*ad nauseum*. Zen-Noh has also filed a federal court lawsuit against LDEQ and a federal court lawsuit against EPA in an effort to use the environmental permitting process improperly to delay and disrupt NS-LA's business ventures, and to further its own barging operations, which will become more expensive if NS-LA occupies the land it lawfully purchased to construct the facilities. Not surprisingly, Zen-Noh's latest round of comments and litigation on the new and modified permits reasserts rejected arguments that LDEQ has not processed the latest permits properly, and that EPA must object to them.

That Zen-Noh is repeating the same claims over and over—despite LDEQ's substantive responses to its comments, EPA's decision thus far not to object to the permits, and the U.S. federal court's dismissal of its unfounded lawsuit—is typical Zen-Noh behavior. Zen-Noh has previously “utilized environmental issues and a strategic public relations plan” to pursue its commercial interests. For example, in Indiana in 2005, Zen-Noh's subsidiary Consolidated Grain & Barge (CG&B) employed the strategy to avoid being eliminated by a conglomerate that threatened its business (because there was room for only one grain processor in the market.) As CG&B's public relations counsel has bragged, there was no real interest in that situation—“This was extremely complex litigation about a relatively dull subject: rail yard storage tracks. Why should anyone care?” CG&B and its hired guns therefore devised a plan to arouse the “environmental front.” To accomplish environmental opposition, CG&B went to a county EPA office and claimed that the Con-Agra facility would harm the county's air quality. They hired an expert to support these unfounded arguments. The EPA official spoke with environmental group leaders. In the PR consultant's words—“Thus began an active environmental campaign against the ConAgra facility.—Front page photo of environmentalists in gas masks demonstrating against the proposed plant” all simply to further CG&B's business efforts.

CG&B followed these public relations stunts with rail yard litigation to oppose ConAgra in Indiana. Not surprisingly, the same lawyers that worked for CG&B in Indiana have appeared in Louisiana federal court for Zen-Noh. Using the same approach as described in Indiana (identify and file “each and every motion that could be filed” i.e., every conceivable legal motion),” Zen-Noh's lawyers filed a completely unfounded federal court suit against LDEQ under the federal Clean Air Act, allegedly to protect Zen-Noh's constitutional rights to due process before LDEQ. The lawsuit alleged that a [*sic*] LDEQ was denying Zen-Noh its rights to public participation under the federal Clean Air Act by providing Zen-Noh insufficient time to comment on the

proposed air permits in the state permitting proceeding. Zen-Noh's lawsuit was dismissed as baseless. The judge remarked in her opinion:

[a]s counsel for Zen-Noh admitted at oral argument, and as the Court confirmed through its own research, there is not a single published case in which a federal court used the Clean Air Act as a basis for interfering in a pending state administrative proceeding. In addition, Zen Noh has struggled to articulate precisely how the defendants in this case will allegedly violate the Clean Air Act. In the absence of a clear legal basis for the lawsuit, and in light of the ongoing nature of the permitting process, the constitutionally proper course is for the court to dismiss the case without prejudice.

A brief description of the LDEQ permitting process to date and of Zen-Noh's previous campaigns to prevent issuance of the NS-LA permits is helpful to provide context for the responses to Zen-Noh's latest comments. The initial permit applications to build a pig iron facility were filed, and the applications were ruled complete, in May 2008. Public notice drafts were issued on October 15, 2008. After a significant delay, Zen-Noh began demanding detailed information from Nucor and LDEQ that it claimed it needed in order to determine for itself the air quality impacts of the project. Its requests included a demand that LDEQ immediately produce all information submitted by Nucor in support of the permit applications, and as appropriate in electronic formats, so that it could perform, independently, each of the permitting analyses that the Clean Air Act and Louisiana rules required Nucor to submit to LDEQ in support of the permit applications. Upon receipt of that information, Zen-Noh hired technical experts to file unfounded, repetitive claims that the information was either insufficient, incorrect, or both, while contending that it had been given insufficient time to comment, all in a transparent attempt to delay the permitting process. Its first comments were dated November 24, 2008 (the last day of the first public comment period). Zen-Noh then filed additional comments dated December 12, 2008; January 28, 2009; April 19, 2010; and May 3, 2010. Zen-Noh also retained consulting firms to submit additional comments on its behalf. LDEQ responded to each of these Zen-Noh comments appropriately and in detail.

The overall theme of Zen-Noh's comments has been that the operation of blast furnaces, coke oven batteries, a sinter plant, heat recovery steam generators, and material storage and handling piles adjacent to its grain operations would cause it harm because of air pollution. Zen-Noh warned of potentially harmful lead, hydrochloric acid mist, sulfuric acid mist, and hydrogen sulfide emissions from NS-LA's coke ovens damaging Zen-Noh's operations, but did so without making any showing that the Nucor facility would emit these air pollutants. Rather, Zen-Noh pointed to permits for other plants in Indiana of a different design than NS-LA's, all the while purposefully neglecting to mention that the Indiana permits had to be amended to be less stringent because their original articulations set emissions levels that were technically impossible to achieve. LDEQ appropriately concluded that NS-LA's operations would not be the same as the Indiana plants, and would not emit the predicted air pollutants, but it still required NS-LA to test for them. (See Zen-Noh comments 61, 63, and LDEQ responses, as reproduced in the LDEQ public comments response summary.) Zen-Noh repeated the very same arguments to LDEQ in additional comments despite the fact that they had already been addressed. (See Zen-Noh comments numbered 90, 208, 261.L.5 through 263.L.5, and LDEQ responses.) The goal of Zen-Noh's efforts is obviously not to offer constructive criticism, but instead to burden the permitting process as it did in its subsidiary's fight in Indiana.

LDEQ Response to Comment No. IV.3

Nucor's comments regarding Zen-Noh are noted for the record.

V. Responses to Comments Submitted by the United States Environmental Protection Agency dated January 7, 2011⁵⁷

EPA Region 6 is encouraged that Nucor is taking a proactive approach in these permit proposals to decrease the amount of emissions, specifically emissions of CO₂ and NO_x, from the Nucor facility. Using an inherently lower emitting process such as the Direct Reduced Iron (DRI) process, and opting to install Selective Catalytic Reduction (SCR) on units such as the coke ovens and sinter plants is breaking new ground in the realm of air pollution control, and is of great benefit to air quality and the environment.

Comment No. V.A.1

Our comments are based on LDEQ's approach to treat the Pig Iron and DRI Plants as separate permitting actions, though as part of the same major stationary source. We are providing comments on the LDEQ's proposed action not to consider these two projects subject to one permitting action. Our comments today should not be construed as an indication as to whether we will grant or deny on a particular issue raised in a Title V petition. Our comments on modeling issues are based on LDEQ's approach and additional modeling concerns will be raised if it is determined that the DRI and Pig Iron Plants should be handled as one PSD permitting action.

LDEQ Response to Comment No. V.A.1

EPA's comment is noted for the record.

Comment No. V.A.2

On October 22, 2010 Nucor submitted their DRI GHG BACT Analysis, and as part of this analysis, included their rationale for why the DRI and pig iron products and processes "cannot be compared directly for the purposes of determining BACT." However, LDEQ needs to provide an adequate record to substantiate why the Nucor Steel Louisiana projects (pig iron and DRI) should or should not be subject to one permitting action. Please provide in the Response to Comments Summary LDEQ's rationale for why the Nucor Steel Louisiana projects (pig iron and DRI) should be considered as separate projects for the purposes of PSD permitting rather than one single new source or one aggregated project subject to one PSD permit. Please explain how your rationale comports with the State's approved SIP, current Federal regulations and policy, court decisions, and EPA petition orders. In particular, LDEQ may find it useful to consider the summary of EPA's historic approach to aggregation (or circumvention) contained in 72 Fed. Reg. 19567, 19570 - 71 (April 15, 2010) (section 111(C)(2)(a)), and the memoranda and determinations cited in that discussion.

LDEQ Response to Comment No. V.A.2

⁵⁷ EDMS Doc ID 7782858

EPA presents two related issues within the comment. The first is whether the “Nucor Steel Louisiana projects (pig iron and DRI) should or should not be subject to one permitting action” (i.e., addressed in the same Prevention of Significant Deterioration (PSD) permit). The second is whether construction of the pig iron manufacturing facility and DRI plants constitutes a single project, thus requiring emissions from the DRI plants to be aggregated with those from the pig iron manufacturing facility to determine applicable requirements under the PSD program. EPA notes that “LDEQ may find it useful to consider the summary of EPA’s historic approach to aggregation (or circumvention)” as set forth in the agency’s April 15, 2010, proposal entitled “Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Aggregation; Reconsideration”⁵⁸ (Aggregation Reconsideration).

First, there are no statutory or regulatory requirements or EPA policy that requires the pig iron and DRI projects to be addressed under “one permitting action” (i.e., a single PSD permit). Neither the Aggregation Reconsideration nor the guidance documents and applicability determinations identified in footnotes 6 – 9 of the proposal state or otherwise imply that a project must be addressed “in a single permit.” In the instant case, the pig iron manufacturing facility and DRI plants are clearly separate and distinct projects; therefore, aggregation of emissions is **not** required.

The discussion of EPA’s “historic approach” in the Aggregation Reconsideration and the guidance documents and applicability determinations identified therein address whether emissions from multiple projects must be aggregated in order to determine whether a PSD significance threshold has been exceeded for a given project. The intent behind EPA’s aggregation policy is to prevent a facility from arbitrarily breaking up a “single” project into component parts that are below NSR threshold levels in order to circumvent NSR by avoiding it completely or delaying it until the facility had been constructed. For example, the Aggregation Reconsideration states:

We calculate the emissions increase associated with a physical or operational change at a major stationary source by reference to *de minimis* thresholds (also known as “significance levels”). From the earliest days of the NSR program, we recognized that a party seeking to avoid major source NSR might attempt to break up a single physical or operational change into nominally-separate changes in order to make the emission increase associated with each change appear to be less than significant.⁵⁹

(Emphasis added).

Nucor has not attempted to make either project “appear to be less than significant” to avoid PSD review. In this case, **both** the pig iron manufacturing facility and DRI plants have undergone PSD review.

Notably, EPA acknowledges that neither “the CAA nor current EPA rules specifically address the basis upon which to aggregate nominally-separate changes for the purpose of making NSR applicability determinations.”⁶⁰ However, EPA’s memorandum entitled “Applicability of New Source Review Circumvention Guidance to 3M – Maplewood, Minnesota”⁶¹ dated June 17,

⁵⁸ 75 FR 19567

⁵⁹ 75 FR 19570

⁶⁰ 75 FR 19568

⁶¹ Memorandum from John B. Rasnic, Director, Stationary Source Compliance Division, OAQPS, to George T.

1993, provides several “criteria to permitting and enforcement authorities to apply when making determinations whether a source is circumventing major NSR through the minor modification process.” Three of the factors that may be considered include:

- Filing of more than one minor source or minor modification application associated with emissions increases at a single plant within a short time period;
- Application of funding; and
- Statements of authorized representatives of the source regarding plans for operation.

Each of these factors is addressed below.

Filing of More than One Minor Source or Minor Modification Application

The 3M memo references a September 19, 1989, memo from John Calcagni to William Hathaway, stating that “two or more related minor changes over a short time period should be studied for possible circumvention.” Although what constitutes a “short time period” is not further discussed, EPA correspondence suggests that “one year between the issuance of permits for modifications at a facility should be suspected of circumvention.”⁶² The permit applications for the pig iron manufacturing facility and the DRI plants were submitted approximately two years and 3 months apart.

Regardless, the 3M and other EPA guidance memos on circumvention share one common theme – the application for one project does not trigger PSD review. As noted above, this is not the case here.

Application of Funding

According to the 3M memo, if “the project would not be funded or if it would not be economically viable if operated on an extended basis (at least a year) without the other projects, this should be considered evidence of circumvention.” In this case, the pig iron project is economically viable without the DRI project, and the DRI project is economically viable without the pig iron project.

Statements of Authorized Representatives of the Source

Nucor has consistently represented the pig iron and DRI projects as being two separate projects co-located at a single source: (1) the pig iron project, originally conceived at 6 million tonnes/year (Phase I and II), with the possible addition of a Phase III steelmaking facility (for which no application has been received); and (2) the DRI plants, which were separately conceived, but co-located with the pig iron facility. The fact that the two projects are co-located means that the interaction between the plants must be considered. The applicant has presented the project as co-located because of the excellent port facilities not otherwise available to Nucor, but separate in making different products, by different processes and technologies, with different end uses, and without process integration or dependency of one process on the other.

In sum, the pig iron and DRI projects do **not** require each other from a technical or economic standpoint. Each facility produces a separate product (pig iron and DRI), the products serve different purposes, and both are separately viable without consideration of the other project. For

Czerniak, Chief, Air Enforcement Branch, Region V

⁶² Letter from Cheryl L. Newton, Chief, Permits and Grants Section, to Mike Hopkins, Ohio Environmental Protection Agency, dated August 8, 1996

these reasons, emissions from the DRI plants need not be aggregated with those from the pig iron manufacturing facility to determine applicable requirements under the PSD program.

Comment No. V.B.1

The proposed permit modification does not contain a PM_{2.5} potential to emit, even though it was included in the initial Title V permit No. 2560-00281-V0 issued May 24, 2010. The permit modification application submitted by Nucor states that “current USEPA guidance recommends that PM₁₀ should be used as a surrogate for PM_{2.5} in the PSD program, which has been done in this application. Accordingly, discussion of PM₁₀ should be regarded as also addressing PM_{2.5}.” LDEQ should provide a rationale as to why PM₁₀ is an appropriate surrogate for PM_{2.5} in this case. Please clarify this issue in the proposed permit and permitting record.

LDEQ Response to Comment No. V.B.1

Permit No. 2560-00281-V0 does not contain emissions limits for PM_{2.5}. As explained in LDEQ Response to Comment No. 5 associated with the original Title V, LDEQ concluded:

Nucor provided a top-down BACT analysis for PM_{2.5}. LDEQ reviewed the analysis and agrees with its conclusion that there are no feasible control technologies or combination of control technologies capable of controlling PM_{2.5} to a higher level than the PM₁₀ control technology originally identified as BACT. Further, modeling results have demonstrated that Nucor’s emissions will not result in violations of the annual and 24-hour PM_{2.5} NAAQS. The combination of the BACT analysis, together with the modeling results for PM_{2.5}, are consistent with the results for PM₁₀ demonstrating that PM₁₀ is, in fact, an adequate surrogate for PM_{2.5}.⁶³

Permit No. 2560-00281-V1 reflects a significant decrease in both PM₁₀ and PM_{2.5} emissions, and does not propose new physical changes or changes in the method of operation.

Comment No. V.B.2

The SOB and Title V Permit “Facility Background and Process Description” states the facility will be comprised of 2 blast furnaces, 2 coke oven batteries, and 280 coke ovens at a permitted capacity of 6 million tonnes of iron per year. Yet the proposed modification is supposed to eliminate one blast furnace, and associated emissions units. It is EPA’s understanding that removing one of the blast furnaces will reduce the capacity by half (3 million tonnes per year), but the permit modification does not state this. The Process Description in the draft permit and SOB reads like the Process Description in the initial Title V Pig Iron Permit. Furthermore, the application states the production capacity at the coke ovens and sinter plant will not be changed. Please clarify in the proposed permit and the record how many blast furnaces, coke batteries, and coke ovens are being permitted in this modification, and what the permitted capacity is (i.e. a practically enforceable production limit).

LDEQ Response to Comment No. V.B.2

The “Background” section of proposed Permit No. 2560-00281-V1 describes the facility as

⁶³ EDMS Doc ID 2947527 (pp. 72 – 74)

currently permitted (i.e., Permit No. 2560-00281-V0). LDEQ will amend this section to clarify that, following the modifications discussed in the proposed permit, the facility will be able to produce approximately 3 million tonnes per year of pig iron using a single blast furnace. As noted by the commenter, the production capacity of the coke ovens (two batteries of 140 ovens each) and sinter plant will not change. The operating rates and federally enforceable emission limitations attributed to the individual emissions units comprising the pig iron manufacturing facility serve to limit the capacity of the operation.

Comment No. V.B.3

It is not clear that the Nucor Pig Iron Permit No. PSD-LA-740 is being modified to include the changes that are being made as part of the Title V modification. The new emission limits for SCR control, emission decreases from the units being transferred to the DRI plant permit, and units being removed from the design of the Pig Iron Plant permit, require the PSD-LA-740 permit to be modified such that the applicable requirements in the modified PSD permit are transferred to the Title V permit. How does LDEQ plan to address this concern?

LDEQ Response to Comment No. V.B.3

LDEQ does not propose to modify PSD-LA-740 based on the fact that the need for selective catalytic reduction (SCR) controls and a supplementary heat recovery steam generator (HRSG) did not stem from LDEQ's BACT determinations, but are now required to demonstrate compliance with the 1-hour NO₂ NAAQS. However, the requirements to install SCR controls and eliminate the coke battery HRSG bypass vents are set forth in Permit No. 2560-00281-V1. Further, this modification eliminates Nucor's authority to construct the sources associated with Blast Furnace #2, even without a modification of the PSD permit.

Comment No. V.B.4

We are encouraged that Nucor is proposing to employ Selective Catalytic Reduction (SCR) as a NO_x control technique at the Pig Iron Plant. EPA believes that this technology is among the most effective for reducing nitrogen oxide emissions from a wide variety of industrial combustion facilities. We are concerned; however, that Nucor stated in their pig iron modification application that SCR is technically infeasible on some of the units, yet the reductions attained from the installation of SCR are being relied upon to show that both the Pig Iron and DRI plant permits do not cause or contribute to a violation of the 1-hour NO₂ National Ambient Air Quality Standard (NAAQS). Pages 2-5 through 2-6 of the permit application discuss why SCR is being considered. "Nucor searched for other potential ways to reduce emissions in order to bring the modeled predictions of NO_x below the [Significant Impact Level] SIL level." It goes on to say "To date, SCR controls have never been applied to coke ovens, sinter plants, or blast furnace gas combustion, either solely or in conjunction with flue gas desulfurization technology as in the MEROS unit test. Nucor believes the application of SCR technology remains technically infeasible for these sources. Nucor is submitting with this permit modification application emissions calculations which reflect the experimental application of SCR to the Coke Oven Main Flue Stacks and the Sinter Plant. While the technical feasibility of these SCR applications is highly suspect, Nucor has decided to take these steps in order to maintain the viability of the NSLA project." If SCR proves not to be technically feasible, then LDEQ must evaluate what further emission reductions can occur or other control technologies that can be utilized to maintain the emission limits that were used to demonstrate that the plant will not cause or

contribute to a violation of the NAAQS. Additionally, a practically enforceable condition in the permits should be included to require Nucor to go through the PSD permitting process and modify their Title V permit if SCR is not technically feasible. At this time, it appears Nucor is implying that the pollution control technology proposed for these permits is technically infeasible but on the other hand they are relying on this technology to achieve reductions to support the issuance of these permits and the potential viability of the project.

LDEQ Response to Comment No. V.B.4

LDEQ concurs with EPA's statement that if "SCR proves not to be technically feasible, then LDEQ must evaluate what further emission reductions can occur or other control technologies that can be utilized to maintain the emission limits that were used to demonstrate that the plant will not cause or contribute to a violation of the NAAQS." Should SCR prove technically infeasible, Nucor would be required to modify Permit No. 2560-00281-V1. In addition, if the "replacement" technology or other facility modifications needed to comply with the 1-hour NO₂ NAAQS result in a significant increase in a "regulated NSR pollutant," PSD review would be required.

Comment No. V.B.5

The Permit Shield in the SOB does not clearly explain why a shield is needed for the coke battery coal charging operations (COK-101 and 201) for 40 CFR 63.303(b)(2). LDEQ's Permit Shield language should list explicitly the requirements that are not applicable, include an explanation of why the requirement does not apply, identify the version of the applicable requirement being shielded, and should only apply to the requirements and units eligible for the shield. In the public record, LDEQ should include its rationale for granting the permit shield.

LDEQ Response to Comment No. V.B.5

40 CFR 70.6(f) states that "the permitting authority may expressly include in a part 70 permit a provision stating that compliance with the conditions of the permit shall be deemed compliance with any applicable requirements as of the date of permit issuance."

40 CFR 63.303(b)(2) of 40 CFR 63 Subpart L – National Emission Standards for Coke Oven Batteries requires charging operations to be equipped with an "emission control system for the capture and collection of emissions in a manner consistent with good air pollution control practices for minimizing emissions from the charging operation." In lieu of an "emission control system," Nucor has proposed to employ negative pressure ovens and compacted coal charging, a state-of-the-art process not contemplated by the federal MACT standard, to comply with the particulate matter limitation of 0.0081 pounds per ton of dry coal charged imposed by 40 CFR 63.303(d)(2). LDEQ has determined that the combination of negative pressure ovens and compacted coal charging will satisfy the requirements of 40 CFR 63.303(b)(2).

Comment No. V.B.6

EPA recommends an enforceable permit condition requiring all emission units subject to performance testing for NO_x to either incorporate continuous emission monitoring, or conduct annual stack testing that requires NO_x, NO, and NO₂ emission data be obtained. If annual stack testing is required, the collection of NO and NO₂ data can be collected at the same time that NO_x is collected, so no additional cost is anticipated. The NO and

NO₂ data will prove valuable for future modeling of this source for the 1-hour NO₂ standard.

LDEQ Response to Comment No. V.B.6

The topgas boilers (PWR-101, PWR-102, PWR-103, and PWR-104) will be equipped with NO_x CEMS per the requirements of 40 CFR 60 Subpart Db. Permit No. 2560-00281-V1 requires stack testing of all other emissions units at the pig iron manufacturing facility with significant emissions of NO_x (COK-102, COK-202, COK-111, COK-211, SIN-101, STV-101, and PCI-101). LDEQ will require Nucor to collect NO and NO₂ data during these stack testing events.

Comment No. V.C.1

Under the Maximum Allowable Emission Rates Table (MAERT), #8 states that all terms and conditions of the initial pig iron TV permit (2560-00281-V0) are also terms and conditions of the DRI PSD permit. LDEQ has stated in the record the DRI plants would be wholly independent of the Pig Iron Plant, but it seems that the language in #8 indicates the permits will share certain conditions and requirements. For the public record, please clarify what requirement #8 in the MAERT actually means. EPA Region 6 realizes certain emission units are being transferred from the Pig Iron Plant to the DRI plant in an effort to make these processes separate and independent. For the public record, LDEQ needs to provide its legal basis and rationale as to how Title V requirements can be transferred and become conditions of a PSD permit. LDEQ should use the State's approved SIP, current Federal regulations and policy, and other authorities as relevant to support its response to these comments. On the basis that the DRI plant is a totally independent project, the PSD must contain all the emission limits for every emission unit in the DRI plant and the PSD analysis. The modeling must also use these maximum emission limits. LDEQ should confirm that this is the process that was used for drafting the PSD permit for the DRI plant.

LDEQ Response to Comment No. V.C.1

The reference to Permit No. 2560-00281-V0 in Specific Condition 8 of proposed PSD-LA-751 is a typographical error. This condition should read, "All emission limitations, monitoring, recordkeeping, and reporting requirements of Permit No. 3086-V0 related to TSP/PM₁₀/PM_{2.5}, SO₂, NO_x, CO, VOC, and CO_{2e} emissions are also terms and conditions of this PSD permit." Specific Condition 8 was included because the Title V contains "testing, monitoring, reporting, and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit" consistent with 40 CFR 70.6(c)(1), and the BACT limitations established by the PSD have been incorporated into the Title V. LDEQ believes such a requirement is preferable, from an administrative perspective, to establishing numerous conditions in PSD-LA-751 identical to those set forth in Permit No. 3086-V0.

LDEQ has confirmed that the sources "moved" from the pig iron manufacturing facility to the DRI facility were indeed included in the modeling for the DRI facility.

Comment No. V.C.2

The original October 2010 application states that Nucor is requesting authorization to construct a reformer-based DRI plant, but is also seeking authority to construct, in the alternative, a reformer-less HYL process unit (inherently less polluting process/experimental). We did not see this other process discussed in the draft PSD

permit, Title V permit, or SOB. Please clarify for the record if this is something Nucor reconsidered before the permit went to public notice, or if these permits are authorizing this alternative process. Please clarify whether this inherently less polluting process was considered in the Best Available Control Technology (BACT) determination. If not, LDEQ should provide its rationale why that process was not evaluated in the BACT determination, especially since Nucor included this process in its application.

LDEQ Response to Comment No. V.C.2

LDEQ received no calculations or process drawings pertaining to a reformerless design. Permit Nos. 3086-V0 and PSD-LA-751 only authorize construction and operation of the emissions units addressed therein; they do not allow Nucor to construct reformerless process units.

Alternative DRI processes are addressed in LDEQ Response to Comment Nos. III.4 and III.7. The HYL process was considered by Nucor and may result in fewer emissions of greenhouse gases; however, this “process is still experimental and has never been attempted at a DRI facility of the size that Nucor is considering.”⁶⁴

Comment No. V.C.3

The PSD permit does not contain CO, NO_x, and SO₂ BACT determinations for Upper Seal Gas Vents (DRI-106 and 206), Furnace Dedusting (DRI-107 and 207), and Product Storage Silo (DRI-112 and 212). LDEQ must provide its rationale in the public record why a BACT determination was not done for these pollutants on those units.

LDEQ Response to Comment No. V.C.3

This information can be found on page 55 of the proposed PSD permit. “BACT for VOC and CO were already determined as good combustion practices for the Reformer Flue gas and so no additional control is feasible for the use of a small portion of this flue gas as seal gas. Sulfur dioxide and particulate matter BACT was determined to treat the spent reducing gas being sent to the Reformer as combustion fuel and so no additional control is feasible for the seal gas.”

Comment No. V.C.4

The draft Title V and PSD permits do not include a PM_{2.5} potential to emit, and LDEQ’s record should justify why PM₁₀ is an adequate surrogate for PM_{2.5} in this case. Additionally, the PM_{2.5} BACT requirements from the PSD permit have not been included in the Title V permit. LDEQ needs to ensure all the requirements of the BACT determination are carried forward to the Title V permit. Additionally, LDEQ needs to ensure the BACT determination requirements are supported by appropriate monitoring; recordkeeping and reporting in the Title V permit to ensure these requirements are practically enforceable.

LDEQ Response to Comment No. V.C.4

Nucor provided a top-down BACT analysis for PM_{2.5} and the requisite modeling analyses to demonstrate that the facility’s emissions will not result in violations of the annual and 24-hour PM_{2.5} NAAQS. As discussed during LDEQ’s conference call with EPA on December 14, 2010,

⁶⁴ IT Questions Response, Section 7.1.2 (EDMS Doc ID 7731649)

LDEQ has agreed to include PM_{2.5} limitations in the final permits.

Comment No. V.C.5

The PSD permit states BACT for DRI-101, 201, 102, 202, 105, and 205 is a fabric filter baghouse achieving 99.5% control of PM_{2.5}/PM₁₀, but this is not carried forward into the Specific Requirements of the Title V permit. LDEQ needs to ensure that all BACT requirements from the PSD permit are carried forward into the Title V permit Specific Requirements to ensure adequate monitoring, recordkeeping, and reporting.

LDEQ Response to Comment No. V.C.5

The requirements noted by the commenter were included in the proposed Title V permit. See Specific Requirement (SR) 18 for DRI-101, SR 37 for DRI-102, SR 54 for DRI-105, SR 166 for DRI-201, SR 185 for DRI-202, and SR 201 for DRI-205.

Comment No. V.C.6

The DRI plant was modeled using maximum short term emissions for PM_{2.5}, PM₁₀, SO₂, and NO_x based on maximum production. LDEQ needs to ensure there are enforceable permit conditions limiting these emissions by having federally enforceable production capacity rates.

LDEQ Response to Comment No. V.C.6

The “Emission Rates for Criteria Pollutants” section of Permit No. 3086-V0 establishes maximum hourly emission rates. General Condition III of LAC 33:III.537 states:

The Emission Rates for Criteria Pollutants, Emission Rates for TAP/HAP and Other Pollutants, and Specific Requirements sections of the permit establish the emission limitations and are a part of the permit. Any operating limitations are noted in the Specific Requirements of the permit.

As such, these emission rates are federally enforceable aspects of the permit (as no limitations are noted as “state-only”). The “Inventories” section sets the maximum operating rate (i.e., production capacity) associated with the emission limitations.

Comment No. V.C.7

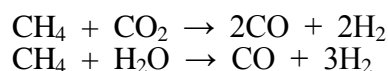
Greenhouse Gas (GHG) BACT Determination: Before providing specific comments, we acknowledge that this is the first GHG analysis conducted by Louisiana and intend the issues we raise to be constructive in building the record for this permit. In addition, we note that the proposal to utilize DRI technology is very much in the spirit of reducing greenhouse gas emissions.

LDEQ’s draft PSD permit contains a proposed CO₂e BACT limit of “good combustion practices” for the Package Boiler and the Reformer/Main Flue Gas Stack based on an efficiency limit, as opposed to establishing a mass- or CO₂e-based limit, based on the proposed BACT review for Nucor’s emissions of GHGs. When determining a PSD permit limit, a permitting authority must establish a numeric emissions limitation that reflects the maximum degree of reduction achievable for each pollutant subject to BACT (e.g., GHG) through the application of the selected technology or technique. However, as

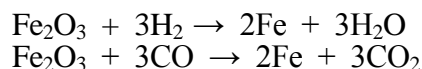
EPA has expressed in its GHG Permitting Guidance, a permit may contain an operational standard, in lieu of a numerical BACT emissions limit, if the permit record demonstrates that a numerical emissions limit for the pollutant under review is infeasible, and if the standard is practically enforceable. Neither the draft permit for Nucor nor the administrative record provides a basis for why establishing a numerical BACT emissions limit is infeasible. In general, a large, non-fugitive source of emissions should be able to directly measure emissions, as we further note in comment 15. In the event that there are compelling reasons that make a numerical limit infeasible, LDEQ should provide that demonstration in the record for this permit.

LDEQ Response to Comment No. V.C.7

Natural gas is not only used as a fuel, but also as a raw material to generate reducing gas. At elevated temperatures, natural gas dissociates into a reducing gas rich in carbon monoxide and hydrogen, which are the primary reductants for the process.



In the DRI reactor shaft furnace, reducing gas will pass up through the iron oxide pellets. The carbon monoxide and hydrogen of the reducing gas scavenge oxygen from the iron oxides from the iron oxide pellet, reducing the oxygenation state of the ores. The resulting products of the reduction process are pure iron, carbon dioxide, and water:



As shown in the reactions described above, in order to remove the oxygen from the iron oxide ore, the DRI process generates CO₂ and water. Limiting the amount of CO₂ that can be created in the DRI reactor would limit the ability of Nucor to create the desired metallization of the finished sponge iron and fundamentally impair the efficiency of the process. Metallization refers to how much of the iron oxide ore has had the oxygen removed so that pure iron remains behind. Not all ores will have iron oxides in the same oxidation state (i.e., the ores will be comprised of varying degrees of FeO, Fe₂O₃, and Fe₃O₅). This variability requires different quantities of reducing gas and CO₂ generation to metalize each ore, which may vary widely based on the mine of origin.

The reducing furnace is essentially a counterflow reactor, intended to generate CO₂ as a fundamental part of the process chemistry. Obtaining the maximum amount of CO₂ per unit of natural gas used in the furnace would demonstrate a high rate of efficiency, since the process would be converting iron oxides to pure “metallized” iron more efficiently. A maximum emission rate limitation would encourage Nucor to design the facility around processing the “worst-case” ore from a CO₂ perspective. For this reason, an output-based efficiency standard is favored over an emission limitation.

An energy efficiency standard is also preferred because it will remain relevant regardless of the production rate of the facility, as opposed to an absolute maximum limit (in pounds per hour and/or tons per year) based on its highest design production rate.

Comment No. V.C.8

The draft PSD permit contains a proposed CO₂e BACT limit of “acid gas separation system” for the Acid Gas Absorption Vent but contains no BACT analysis explaining

how that control technology was selected. In addition, the permit does not contain a numerical GHG emission limit based on application of that control. As explained above, the permit must contain a numerical BACT limit or explain why establishing a numerical emissions limit for the pollutant under review is infeasible. LDEQ should include in the permit and/or the administrative record a basis for establishing an acid gas separation system as CO₂e BACT, and provide a numerical BACT emissions limit (or explain why one is infeasible).

LDEQ Response to Comment No. V.C.8

The acid gas absorption system does not itself generate CO₂ emissions. The system acts as BACT for CO₂ generation in the reduction furnace by removing CO₂ from the equilibrium of the reduction reaction, increasing efficiency in the furnace, and thereby reducing the overall quantity of CO₂ formed and emitted. The acid gas absorption vent thus acts as a control device through which captured CO₂ passes.

The inclusion of this device as BACT for CO₂ emissions from itself in the BACT summary table of PSD-LA-741 is a typographical error. The CO₂e BACT reference has been removed from the summary table in the Briefing Sheet of the permit.

Regarding a numerical BACT limitation, see LDEQ Response to Comment No. V.C.7.

Comment No. V.C.9

The draft PSD permit does not provide baseline GHG emissions rates from the Direct Reduced Iron (DRI) plant in the administrative record for this permitting action. Establishing baseline emissions is a typical first step for a PSD pollutant applicability analysis. In this case, LDEQ has determined that the emissions from the DRI plant are above the thresholds for PSD permits, but the permit does not quantify such emissions in the administrative record for the permit application. LDEQ should provide the total GHG estimated emissions for the DRI plant as the basis of the decision for applicability under the GHG tailoring rule (75 FR 31514, June 3, 2010). Baseline emissions are necessary in order to determine (1) major modification applicability for this new plant in the future, when there are changes to the existing design during the construction or operational phases of this plant, and (2) if the proposed conditions and restrictions which limit emissions from a new source achieve the "best available" control of those emissions. LDEQ should provide an estimate of baseline GHG emissions in the permit record or clearly indicate why at this time it is infeasible to provide such emissions.

LDEQ Response to Comment No. V.C.9

LDEQ estimates CO₂ emissions from the DRI plants to be approximately 3.39 million metric tons per year (equivalent to 3.73 million standard tons) based on the BACT limit of 13 decatherms of natural gas per metric ton of DRI. LDEQ derives this estimate in the following manner:

$$[13 \text{ MMBtu} / \text{tonne of DRI}] \times [5,000,000 \text{ tonnes of DRI}] = 65,000,000 \text{ MMBtu}$$

$$[65,000,000 \text{ MMBtu}] \times [1,000,000 \text{ Btu} / \text{MMBtu}] = 65 \times 10^{12} \text{ Btu}$$

$$[65 \times 10^{12} \text{ Btu}] / [23,879 \text{ Btu} / \text{lb methane}] = 2,722,057,038 \text{ lbs methane}$$

$$[2,722,057,038 \text{ lbs methane}] / [16.04 \text{ lbs of methane / mol}] = 169,704,304 \text{ mols}$$

$$[169,704,304 \text{ mols}] \times [44.01 \text{ lbs CO}_2 / \text{mol}] = 7,468,686,423 \text{ lbs CO}_2$$

$$[7,468,686,423 \text{ lbs CO}_2] / [2,000 \text{ lbs / ton}] = 3,734,343 \text{ tons CO}_2$$

$$[3,734,343 \text{ tons CO}_2] / [1.102 \text{ tons / tonne}] = 3,388,696 \text{ tonnes CO}_2$$

This figure should be viewed as conservative (i.e., as overstating CO₂ emissions), as it does not discount the carbon molecules that will remain in the DRI product. Actual emissions will be confirmed once operations commence. LDEQ understands that CO₂e emission rates will be needed to determine whether future physical changes or changes in the method of operation result in a significant net emissions increase.

Comment No. V.C.10

The preliminary determination in the air permit evaluates BACT for CO₂ emissions; however, this information is missing from the BACT table in the permit. GHG BACT and these analyses have been provided by the applicant and, therefore, should be appropriately addressed in this table. Further, LDEQ should explain in the record why BACT was not addressed for other GHG permitting pieces of equipment that are part of the DRI process.

LDEQ Response to Comment No. V.C.10

The BACT limit of 13 MM Btu per tonne of DRI produced will be added to the Specific Conditions of the PSD permit. PSD-LA-751 addresses all sources of GHG emissions at the DRI plants. See LDEQ Response to Comment Nos. V.C.7, V.C.16, and V.C.17.

Comment No. V.C.11

NUCOR's BACT determination for the DRI process considered the acid gas absorption system that will produce pure CO₂ capable of Carbon Capture and Storage (CCS). However, the draft permit does not evaluate CCS, which the EPA's GHG permitting guidance notes on pp.33-34 is an available technology for industrial facilities with high-purity CO₂ streams, which includes iron and steel production. LDEQ should provide a basis for why CCS is not considered an available technology, and if it is considered available but not technically feasible (as Nucor's 10/22/10 letter suggests), please provide a basis for such determination. See GHG permitting guidance at pp. 36-38.

LDEQ Response to Comment No. V.C.11

LDEQ has evaluated both dedicated sequestration and transport and sequestration.

Dedicated Sequestration

Dedicated sequestration involves the injection of CO₂ into an on-site or nearby geological formation, such as an active oil reservoir (enhanced oil recovery), a brine aquifer, an un-mined coal seam, basalt rock formation, or organic shale bed. Clearly, in order for geologic sequestration to be a feasible technology, a promising geological formation must be located at or very near to the facility location.

According to the U.S. Department of Energy (DOE),⁶⁵ no basalt formations exist any nearer to the project site than Alabama. Organic-rich shale basins and un-mineable coal areas exist in northern Louisiana, but not in the region of southeast Louisiana where the facility will be located.

Saline formations are layers of porous rock that are saturated with brine. These formations are known to exist throughout southern Louisiana. However, as described by the DOE, “less is known about saline formations because they lack the characterization experience that industry has acquired through resource recovery from oil and gas reservoirs and coal seams. Therefore, there is an amount of uncertainty regarding the suitability of saline formations for CO₂ storage.”⁶⁶ LDEQ was unable to find characterization studies of saline formations in the region of southeastern Louisiana, including in the vicinity of the project site in Convent, and no saline sequestration projects have been proposed along the Gulf coast. Due to the high degree of uncertainty in utilizing saline formations for dedicated CO₂ storage, this type of sequestration was deemed technically infeasible.

Louisiana is well known as a major producer of oil and natural gas; therefore, the sequestration of CO₂ in oil and gas reservoirs through enhanced oil recovery techniques may be feasible. While St. James Parish serves as a major transshipment corridor for natural gas, petroleum, and petroleum products, it was found that very few oil and gas wells exist in St. James Parish and the vicinity of Convent. The nearby Maurepas Swamp basin is virtually devoid of oil and gas production. One active field exists in St. James Parish on the west bank of the Mississippi River, but this field is a natural gas producer and is not depleted; CO₂ injected here would simply be reclaimed by natural gas production operations. Without a nearby active oil reservoir, or depleted natural gas reservoir, this option becomes technically infeasible.

Transport and Sequestration

Off-site sequestration of CO₂ involves utilization of a third-party CO₂ pipeline system in order to transport CO₂ to distant geologic formations that may be more conducive to sequestration than sites in the immediate area. Building such a pipeline for dedicated use by a single facility is almost certain to make any project economically infeasible. However, such an option may be effective if both adequate storage capacity exists downstream and reasonable transportation prices can be arranged with the pipeline operator.

Denbury Resources operates a dedicated CO₂ pipeline in the general area of the proposed location of the Nucor facilities. However, the nearest branch of this pipeline is approximately 8 miles distant and across the Mississippi River. Access to this pipeline without a river crossing is approximately 20 miles. In order for use of Denbury’s pipeline to be viable, Nucor would, of course, have to connect to it. To do so, Nucor would have to secure the necessary right-of-ways (or perhaps purchase additional property), construct a 20-mile pipeline (or if the shorter leg is selected, tunnel under the Mississippi River), purchase additional compression equipment with ongoing electricity and maintenance requirements, and likely obtain the approval of other regulatory agencies. In sum, the feasibility of connecting to Denbury’s CO₂ pipeline, both from a logistical and an economic perspective, is, at best, unknown.

LDEQ is also concerned about any permit condition which would, in effect, direct Nucor to

⁶⁵“2010 Carbon Sequestration Atlas of the United States and Canada,” Third Edition, U.S. Dept. of Energy, National Energy Technology Laboratory. See http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/.

⁶⁶ *Ibid.*, p. 27.

contract with a specific, single third party that would act in the capacity of an essential utility, especially given that Denbury's CO₂ pipeline is not regulated by the Louisiana Public Service Commission. LDEQ's position is that any such condition, regardless of the individual circumstances, is beyond the scope of a BACT determination. For this reason, transport and sequestration was eliminated from further consideration.

Comment No. V.C.12

LDEQ in the BACT analyses for GHG considers limits on the natural gas fuel usage as "no more than" 13 MMBtu per tonne of DRI produced. However, as noted above, the BACT limit established in the permit must be practically enforceable. In this case, the fuel gas specification needs to be contained in the permit to be practically enforceable as the BACT for the DRI plant. For determining the CO₂e emission limit, the production rates are being monitored in the Specific Requirements, but this should also be federally enforceable. Please include the production rates in the permit as a federally enforceable condition.

LDEQ Response to Comment No. V.C.12

EPA's comment in regards to fuel gas specification is not specific. Natural gas quality and composition changes frequently, to a greater or lesser degree, over time and even from the same source. For this reason, natural gas is typically sold on the basis of energy units (therms, or 100,000 British thermal units), to avoid the confusion of comparing volumetric or mass-based measurements of gases with differing compositions. Requiring a specific natural gas composition is not practical.

A federally enforceable condition requiring production rates to be monitored has been added to the Specific Requirements. See LDEQ Response to Comment Nos. V.C.16 and V.C.17.

Comment No. V.C.13

Regarding the proposed efficiency limit for the DRI process, the permit does not express the type of DRI process that Nucor intends to construct and employ, and Nucor's letter of 10/22/10 notes that they are "in the process of evaluating specific designs..." We understand that the Midrex process represents the majority of DRI production capacity worldwide, followed by the Mexican HYL-III process. Assuming Nucor plans to install the Midrex technology, as of 2006 Midrex quoted efficiency levels in the range of 2.3 to 3.0 gigacal/t DRI. In converting the units, 2.3 to 3.0 gcal/ton becomes 9.1 to 12 MMBtu/ton DRI, or 10.1 to 13.1 MMBTU/tonne. Assuming the Midrex technology will be employed, Nucor's statement that "no more than 13 MMBTU/tonne" appears accurate, and we encourage LDEQ to explore the latest DRI technologies and establish an efficiency limit that allows for the maximum degree of reduction of GHG emissions from the chosen process.

LDEQ Response to Comment No. V.C.13

LDEQ reviewed literature related to a number of other DRI processes (e.g., see LDEQ Response to Comment No. III.7). The limit of 13 MM Btu/tonne of DRI produced reflects BACT for greenhouse gases.

Comment No. V.C.14

BACT for the reformers has been evaluated without providing the control effectiveness of each control. In evaluating the effectiveness, the GHG emission controls, the amount of the pollutant emitted per product produced should be specified where feasible. LDEQ has only specified energy integration in MMBtu/tonne of DRI iron produced. As explained above, if a numerical emission limit (e.g., ton of CO₂ per tonne of DRI produced) is infeasible, LDEQ should explain why it is infeasible to express the BACT limit as a numerical limit on the amount of GHG emissions.

LDEQ Response to Comment No. V.C.14

See LDEQ Response to Comment No. V.C.7.

Comment No. V.C.15

LDEQ should provide a rationale in the record why CO₂ analyzers are not being used to determine emissions limits for the DRI plant. Additionally, the term “good combustion practices” is used for CO and GHG BACT control, but it does not have adequate monitoring for CO₂ control, which is necessary in determining the compliance with the combustion standard.

LDEQ Response to Comment No. V.C.15

NO_x CEMS will be required on the Reformer Main Flue Stacks (DRI-108, DRI-208) per Specific Requirements 72 and 231 of Permit No. 3086-V0. These requirements will be modified to require that a CO₂ continuous emission monitoring system (CEMS) be installed as described in Performance Specification 2 of 40 CFR 60 Appendix B.

Regarding monitoring of CO₂ emissions from the package boiler, see LDEQ Response to Comment Nos. V.C.16 and V.C.17.

Comment No. V.C.16

Consistent with the comments above, LDEQ should include the CO₂e BACT limits for the Package Boiler, the Reformer/Main Flue Gas Stack, and the Acid Gas Absorption Vent in the Specific Conditions section of the permit. Numerical limits and/or operation standards (including “good combustion practices” for CO and VOC) are provided in this section, but similar limits for CO₂e are not included in this section.

Comment No. V.C.17

Please clarify in Specific Requirements Nos. 81 and 236 that BACT is for GHG or CO₂e. Also, please indicate monitoring for BACT on CO₂e for the Package Boilers in the Specific Requirements.

LDEQ Response to Comment Nos. V.C.16 and V.C.17

The BACT limit established by PSD-LA-751 for GHG emissions is 13 MM Btu (i.e., decatherms) per metric ton (or tonne) of DRI produced. It accounts for the natural gas consumed by **all** combustion sources at the facility, including the reformers, package boilers, and hot flares, as well as the natural gas used as a reactant in the reducing furnace, inclusive of all startup/shutdown emissions and off-spec production. This BACT limit would be more appropriately attributed to the entire facility (and thus placed under UNF 0002 in Permit No.

3086-V0). The permit will be modified accordingly, and LDEQ will clearly identify it as BACT for GHG (CO₂e) emissions.

Establishing BACT on a facility-wide basis is consistent with EPA’s “PSD and Title V Permitting Guidance For Greenhouse Gases,” which states that:

For new sources triggering PSD review, the CAA and **EPA rules provide discretion for permitting authorities to evaluate BACT on a facility-wide basis** by taking into account operations and equipment which affect the environmental performance of the overall facility. The term “facility” and “source” used in applicable provisions of the CAA and EPA rules encompass the entire facility and are not limited to individual emissions units.⁶⁷

(Emphasis added.)

The associated monitoring provisions must be designed to verify compliance with the 13 MM Btu/tonne DRI BACT limit. As such, the amount of natural gas consumed by the process, including its heating value, and the amount of DRI product produced are the only necessary parameters. Therefore, Specific Requirements 82 and 235 in proposed Permit No. 3086-V0 will be deleted and replaced with the following specific requirements under UNF 0002:

- BACT for greenhouse gas (CO₂e) emissions: Monitor the total DRI facility natural gas and energy consumption monthly by maintaining a master flow meter that totals natural gas consumed by the DRI process. Conversion from natural gas volume to energy consumption shall be based on the natural gas analysis provided by the supplier, or direct sampling by the facility, for the same month and reflect the HHV of the gas. [LAC 33:III.509]
- BACT for greenhouse gas (CO₂e) emissions: Retain monthly records of total DRI facility natural gas and energy consumption, in decatherms. Maintain these records for a period of at least five years. [LAC 33:III.509]
- BACT for greenhouse gas (CO₂e) emissions: Maintain monthly records of total DRI production from the reduction furnace, inclusive of off-spec material and captured DRI dust, in metric tons produced. Maintain these records for a period of at least five years. [LAC 33:III.509]
- BACT for greenhouse gas (CO₂e) emissions: Determine compliance with the GHG BACT limitation of 13 decatherms per metric ton of DRI by maintaining a trailing twelve-month rolling average of natural gas consumption less than or equal to 13 decatherms per metric ton of DRI. The rolling average shall be calculated from the records of actual natural gas consumption and actual DRI production required by this permit. Maintain records of the rolling average for a period of at least five years. [LAC 33:III.509]

Comment No. V.D.1

Nucor did not submit a modeling protocol for the DRI permit to be reviewed prior to submitting modeling. There are several items in our comments below that could have been addressed in a modeling protocol review and may have negated the requirement to

⁶⁷ Pg. 24

deal with these issues as part of the public comment period. We recommend that any future permitting at this facility include sufficient time to allow for development and approval of a modeling protocol prior to performing ambient impact analyses.

LDEQ Response to Comment No. V.D.1

LDEQ notes EPA's concern with a lack of protocol. While a protocol is not strictly required by regulation, LDEQ understands the importance of the protocol process and encourages applicants to submit a protocol prior to commencement of actual modeling.

Comment No. V.D.2

PM2.5 - We note that Nucor did a cumulative analysis for PM2.5, but only included receptors that were within the radius of significance of the DRI process. We note that previous modeling for the Pig Iron process included numerous receptors that were 3-5 km away (many around the Motiva facility) with exceedances predicted. Nucor previously verified that they were not contributing significantly to those exceedances. However, for the proposed permit modifications (Pig Iron process), Nucor did not verify or justify that its revised impacts were not significant for those previously modeled exceedances after the proposed modifications (which include some emission reductions, increased stack heights, and changes in emission characterizations).

LDEQ Response to Comment No. V.D.2

Nucor followed the correct modeling process for modeling a project. The significance area for the DRI plants did not include the receptors noted in the comment; therefore, these receptors were not included in the DRI Facility's model. Nucor was able to demonstrate in the original pig iron manufacturing facility modeling that its impact at these receptors was insignificant at the point and time of any exceedance.

Although the pig iron manufacturing facility's permit is being modified, there is an overall decrease of 104.13 tons per year from the pig iron manufacturing facility; therefore, it is reasonable to believe that the impact would also decrease.

Comment No. V.D.3

SO2 - We note that Nucor modeled the DRI activities against the 1-hr standard and showed impacts that were below the interim SIL, so no cumulative analysis was conducted for SO2. We note that previous modeling for the Pig Iron process included numerous receptors that were 3-5 km away (many around the Motiva facility) with exceedances predicted for the 3-hour and 24-hour SO2 Standards. Nucor previously verified that they were not contributing significantly to these exceedances. However, for the proposed permit modifications (Pig Iron process), Nucor did not verify or justify that its revised impacts were not significant for those previously modeled exceedances after the proposed modifications (which include some emission reductions, increased stack heights, and changes in emission characterizations).

LDEQ Response to Comment No. V.D.3

Nucor followed the correct modeling process for modeling a project; therefore, cumulative 1-hour SO2 modeling was not required. Although the pig iron manufacturing facility's permit is being modified, there is an overall decrease in SO2 emissions of 845.01 tons per year, and Nucor has

removed the HRSG bypasses. Therefore, it is reasonable to believe that the impact would decrease at all receptors, not increase, even with the changes in the stack parameters. Nucor was able to demonstrate in the original pig iron manufacturing facility modeling that its impact at these receptors was insignificant at the point and time of any exceedance.

Comment No. V.D.4

There is a concern regarding a statement Nucor made in its permit application. “Nucor determined that AERMOD cumulative modeling predicts order of magnitude exceedances of the 1-hour NO₂ NAAQS even without contributing sources from the Nucor [Nucor Steel Louisiana] NSLA and DRI facilities.” We also note that LDEQ will likely need to conduct additional modeling in this area in investigating and resolving previously modeled violations of ambient standards (i.e. PM₁₀, PM_{2.5}, and 3-hour and 24-hour SO₂ standards) around nearby facilities based on previous modeling for the Pig Iron process. As the air quality planning and permitting authority in Louisiana, LDEQ has a responsibility to prevent significant deterioration of air quality and attain ambient standards including the PM₁₀, PM_{2.5}, SO₂, and 1-hour NO₂ NAAQS [40 CFR 51.166(a)(1)-(3)]. How does LDEQ plan to address these issues?

LDEQ Response to Comment No. V.D.4

LDEQ is aware of the previously modeled violations of the NAAQS (for which Nucor was able to demonstrate it was not a significant contributor) and of its obligation to remedy the violations within a timely manner. LDEQ has already begun looking into this issue and will continue to do so. LDEQ will comply with all requirements of EPA’s SIP call if and when it is issued. Should reductions be necessary to attain the standard, LDEQ will utilize proper procedures to achieve these reductions using the SIP process. However, this issue is not relevant to the current permit action.

Comment No. V.D.5

We also note that LDEQ will likely need to perform 1-hour SO₂ modeling in this area in the near future as part of its SO₂ maintenance plans and we encourage LDEQ to conduct some modeling to determine whether Nucor’s combined emissions (DRI and Pig Iron process) will not need to be reduced in the future as part of the maintenance plan.

LDEQ Response to Comment No. V.D.5

EPA’s concern is duly noted. Should modeling need to be performed for the 1-hour SO₂ attainment demonstration, such modeling will be performed at that time in accordance with EPA’s guidelines for performing attainment modeling. Should reductions be necessary to attain the standard, LDEQ will utilize proper procedures to achieve these reductions using the SIP process. However, this issue is not relevant to the current permit action.

Comment No. V.D.6

NO₂ - Nucor is installing SCR on both Pig Iron and DRI NO_x emission units. They modeled the Pig Iron and DRI emission units together and modeled just below (7.46 vs. 7.48 µg/m³) the interim SIL using a 75% ARM adjustment. EPA’s current guidance is that conversion ratio of 90% (the current general default equilibrium ratio used in NO₂ analyses) is what these type of analyses should start with, and that some justification is necessary to use lower levels, including a level as low as the 75% conversion ratio

(especially for significance modeling). EPA has indicated that a potential justification, if a source wishes to use the ARM ratio (75% conversion ratio), could be that highest modeled values are from night-time meteorology and therefore conservative. Nucor indicated that App. W, allows for the use of ARM without providing any additional justification. EPA stated in our June 29, 2010 NO₂ modeling guidance that justification should be provided if an applicant wishes to use the lower conversion rate.

We note that some of the emission units have an 83% NO_x control efficiency. One solution may be to further lower NO₂ modeled impacts would be to tighten the SCR limits to 90% or greater on some units to get below the interim SIL level with a 90% conversion ratio. Another option could be that Nucor revise their analysis with a PVMRM based modeling analyses. This would necessitate development of a modeling protocol to conduct this additional analysis. A PVMRM analysis may be able to show the Nucor facility (Pig Iron and DRI sources) impacts are below the NO₂ interim SIL. We will continue to work with LDEQ as you substantiate the record and address these comments.

LDEQ Response to Comment No. V.D.6

40 CFR 51 Appendix W describes a multi-tiered approach to modeling NO_x emissions. Because the standard is in the form of NO₂, not NO_x, EPA recognizes that assuming all NO_x is NO₂ will be overly conservative. In the multi-tiered approach, the initial screen uses a Gaussian model to estimate the maximum concentration and assumes a total conversion of NO to NO₂. If the results are too conservative, they can be multiplied by an empirically derived NO₂/NO_x value of 0.75. The NO₂/NO_x factor of 0.75 can be applied to the NO₂ significance modeling as well as to refined modeling.⁶⁸

The majority of NO_x emissions are initially emitted as NO from source stacks. This is acknowledged by EPA's Addendum to the AERMOD Implementation Guide⁶⁹, which allows a default 0.10 in-stack ratio of NO₂/NO_x in the Plume Volume Molar Ratio Method (PVMRM). Presumably, as this is a default value, this value is also conservative. Indeed, the San Joaquin Valley Air Pollution Control District has compiled a list of NO₂/NO_x ratios⁷⁰ that can be used as default in-stack ratios. All of the listed sources have a recommended ratio of less than 0.20; most of the recommended values are below 0.10.

Additionally, in many applications, the maximum impact due to the facility being modeled occurs in close proximity to the plant's emission sources. For the Nucor Plant, the receptor point having the maximum 1-hour NO₂ concentration (averaged over the 5 year meteorological database) was approximately 1350 meters from the DRI reformer stacks (DRI-108 and DRI-208). Typically, with such a short distance from the source to the maximum near field impact, the timeframe is too short for a majority of the NO to convert to NO₂. The OLM/ARM Workgroup noted in its May 27, 1998 document⁷¹ on the use of the ambient ratio method (ARM) that the original description of the ARM indicated the distance where the typical NO_x

⁶⁸ March 15, 2002 memo from Daniel J. deRoeck to Richard Daye, available at <http://www.epa.gov/ttn/nsr/gen/ratio.pdf>

⁶⁹ October 2009 version is available on EPA's SCRAM website, http://www.epa.gov/ttn/scram/dispersion_prefrec.htm

⁷⁰ Available at http://www.valleyair.org/busind/pto/Tox_Resources/Assessment%20of%20Non-Regulatory%20Option%20in%20AERMOD.pdf

⁷¹ Available at <http://www.dec.state.ak.us/air/ap/docs/sitearm.pdf>

composition within the plume has stabilized could be greater than 10 kilometers from the emission source and that the ARM would conservatively estimate near-field NO₂ impacts. Also, as noted in the June 2005 MACTEC Report for the Alaska Department of Environmental Conservation Division of Air Quality on the evaluation of bias in the PVMRM⁷², “Bofinger et al. (1986) states that ‘the plume centerline ratio of NO₂ to total oxides of nitrogen (NO_x) does not exceed a value of 80% conversion for plume ages of the order of seven hours.’”⁷³

Based upon the fact that NO_x is generally emitted as NO and the highest receptor concentrations are near the facility, it is unlikely that most of the NO will have converted to NO₂ at these receptors. Therefore, the application of the national annual default conversion factor (0.75) is reasonable as applied to predicted NO_x concentrations at this distance. Even the June 28, 2010⁷⁴ 1-hour NO₂ modeling guidance does not specifically disallow the use of the 0.75 ARM. It simply states, “such application of Tier 2 for 1-hour NO₂ compliance demonstrations **may** need to be considered on a source-by-source basis in **some** cases [emphasis added].”

The conversion of NO to NO₂ is also dependent on available ozone. Available ozone causes the conversion to NO₂ to increase. Looking at the meteorological conditions for the maximum predicted 1-hour average concentration for the receptor point having the maximum 5-year average 1-hour NO₂ concentration (705889, 3328026), the following conditions are noted:

Year	Concentration (µg/m ³)	Date	Hour	Temperature (°F)
2001	6.97	February 23	0900	48
2002	6.80	January 12	1100	50
2003	8.11	August 13	0800	72
2004	6.90	March 17	1000	67
2005	8.43	November 19	1000	53

Although this is only one case, it appears that most of the hours which result in the predicted highest 1-hour average for this receptor are during the winter months, mid-morning, and low temperature, which would not correlate to high ozone concentrations. These conditions support using the traditional NO₂/NO_x conversion factor of 0.75 for the 1-hour averaging period.

Looking at all of the receptors with a five-year average modeled concentration above 7.5 µg/m³, when the individual year data points for those receptors was above a modeled concentration of 7.5 µg/m³ and when ozone is mostly likely to be present (late morning and afternoon), the occurrences above 7.5 µg/m³ occur almost exclusively in colder months (November – March). During peak ozone season (May-September), the highest concentrations of NO_x (above 8.33 µg/m³) occur exclusively between the hours of 7 a.m. – 9 a.m. and 8 p.m. – 11 p.m. During these timeframes, it is unlikely that ozone chemistry is favorable for conversion of NO to NO₂.

Finally, it should be noted that the cumulative modeling is not required by the PSD program. PSD regulation requires modeling of independent projects. The pig iron manufacturing facility and DRI plants are separate projects and should be modeled separately to determine the extent of

⁷² Available at http://www.epa.gov/scram001/7thconf/aermod/pvmrm_bias_eval.pdf

⁷³ Bofinger, N.D., P.R. Best, D.I. Cliff, and L.J. Stumer. 1986, “The oxidation of nitric oxide to nitrogen dioxide in power station plumes,” Proceedings of the Seventh World Clean Air Congress, Sydney, 384-392.

⁷⁴ Memo from Tyler Fox to the Regional Air Directors, available at http://www.epa.gov/ttn/scram/ClarificationMemo_AppendixW_Hourly-NO2-NAAQS_FINAL_06-28-2010.pdf

compliance. The DRI permit application included modeling.⁷⁵ The modeling indicated a maximum 1-hour NO₂ impact of 6.14 ug/m³, with 100% conversion of NO to NO₂. This is below EPA's interim significance level of 7.5 ug/m³. Therefore, the DRI project is insignificant in regards to NO_x emissions, and a cumulative impact analysis is not required.

LDEQ believes that the pig iron manufacturing facility would also likely prove to be insignificant in regards to NO_x emissions if modeled on its own, which is the proper modeling procedure for a single project, and therefore, cumulative modeling would not be required. LDEQ modeled the highest overall receptor (highest 5-year average) and the highest receptor for each individual year. Averaged over five years, all six receptors passed while assuming 100% conversion of NO to NO₂. Not only do these receptors represent the highest modeled concentrations in the cumulative modeling, but the receptors are on different sides of the plant and are able to account for different wind directions. A summary of the results of this investigation are in the table below.

UTM Coordinates		5-Year Average
704188.9	3325326	6.21
703788.9	3328926	6.66
705788.9	3332426	6.92
705888.9	3327126	6.85
712188.9	3329526	6.17
705888.9	3328026	6.88

In summary, LDEQ believes that the use of the ARM and the annual default NO₂ to NO_x ratio of 0.75 is valid. The fact that most emissions occur as NO and the impacts occur close to the facility impedes the time required to convert NO to NO₂. Additionally, the highest concentrations of NO_x generally occur during cooler parts of the day and cooler times of the year; therefore, less ozone is available for conversion of NO to NO₂. Moreover, cumulative modeling is not required by the PSD program, and the DRI plants have already demonstrated compliance with the NO₂ modeling requirements on its own.

Comment No. V.D.7

CLASS I - Nucor did not appear to appropriately address Class I SIL/increment to determine if a full Class I increment analysis should have been performed. Nucor relied upon guidance from the National Park Service (NPS) that used a Q/D ratio to determine if visibility or AQRV's should be analyzed. EPA does not approve of the use of the NPS guidance for screening out of conducting a Class I increment analyses. Previous CALPUFF modeling databases could be used to demonstrate that Nucor's (DRI process) impacts are below the EPA proposed Class I SIL level for the PSD triggered pollutants.

LDEQ Response to Comment No. V.D.7

Based upon potential emissions of the DRI plants and its proximity to the Class I area, LDEQ concluded that Class I increment modeling was not warranted. Previously, the pig iron manufacturing facility's emissions were modeled for the Class I increment with emissions of 681.05 TPY of PM₁₀, 3781.87 TPY of SO₂, and 3791.83 TPY of NO_x. This demonstration

⁷⁵ EDMS Doc ID 6592414 (pg. 166)

showed compliance with the Class I increment. Nucor has since reduced those emissions by 213.66 tons/yr of PM₁₀, 845.01 tons/yr of SO₂ and 3334.67 tons/yr of NO_x. Even with the addition of the emissions of the DRI Facility, there is an overall reduction of 78.10 TPY of PM₁₀, 816.67 TPY of SO₂, and 3217.05 TPY of NO_x. Therefore, it stands to reason that this new project should not adversely affect the Class I area. LAC 33:III.509.P requires additional notifications and analyses for areas impacting Federal Class I Areas. To date, “affected by” has been interpreted by the following policy agreed to with the Federal Land Manager, and EPA has never objected to this approach.

In order to determine whether a source may affect a Class I area, LDEQ uses the Q/d approach. Q/d refers to the ratio of the sum of the net emissions increase (in tons) of PM₁₀, SO₂, NO_x, and H₂SO₄ to the distance (in kilometers) of the facility from the nearest boundary of the Class I area.

$$Q/d = \frac{PM_{10\ (NEI)} + SO_{2\ (NEI)} + NO_{x\ (NEI)} + H_2SO_{4\ (NEI)}}{\text{Class I km}}$$

Where:

PM _{10 (NEI)}	=	net emissions increase of PM ₁₀
SO _{2 (NEI)}	=	net emissions increase of SO ₂
NO _{x (NEI)}	=	net emissions increase of NO _x
H ₂ SO _{4 (NEI)}	=	net emissions increase of H ₂ SO ₄
Class I km	=	distance to nearest Class I area (in kilometers)

If Q/d ≥ 4, LDEQ would formally notify the FLM in accordance with LAC 33:III.509.P.1. For the DRI plants, the Q/d is 1.36; therefore, it is reasonable to assume that no adverse impact to the Class I area will be realized by this project.

Although LDEQ felt that it was unnecessary, Nucor supplied Class I modeling on December 20, 2010, in order to satisfy EPA’s request. The impacts were compared to the EPA’s 1996 proposed significant impact limits⁷⁶ and are summarized in the following table. No adverse impact should occur to Breton from the addition of the DRI Facility.

Pollutant	Averaging Time	SILs (µg/m ³)	Modeled Results (µg/m ³)
SO ₂	Annual	0.1	0.000195
	24-hour	0.2	0.0078
	3-hour	1.0	0.026
PM ₁₀	Annual	0.2	0.00083
	24-hour	0.3	0.031
NO _x	Annual	0.1	0.000115

Comment No. V.D.8

Ozone impact analysis: We note that it does not appear that the ozone impact analyses has [*sic*] been updated for the 75 ppb 8-hour standard. The DRI process trigger [*sic*] PSD

⁷⁶ 61 FR 38250

for the ozone precursor, NO_x. Nucor previously conducted photochemical modeling in 2008 for the proposed emissions from the Pig Iron process and the 85 ppb 8-hour ozone standard. EPA recommends that Nucor/LDEQ evaluate the modeling outputs from the previous analyses and compare them with the new NO_x emission rates to yield some analysis on the impact of Nucor's emissions on ozone levels for the 75 ppb standard.

LDEQ Response to Comment No. V.D.8

Ozone modeling was included in the first pig iron manufacturing facility application. The modification application has reduced the total NO_x emission by 3334.67 TPY. This is an 88% reduction in emissions. Even with the addition of the DRI plants, total site-wide NO_x emissions decrease by 85%. In the original modeling, Nucor's emissions result in an approximately 3 to 6 percent increase over the base case modeling estimates. For the "grid cells greater than 80 ppb anytime during an episode" metric, Nucor's emissions contribute very slightly, 0.3 to 1.0 percent. For the "daily maximum near a monitor station" metric, Nucor contributes a maximum 0.88 percent increase, and on the majority of days, less than a 0.1 percent increase. It stands to reason that since the NO_x emissions have been drastically reduced, and VOC emissions have also declined, the original modeling is a vast overestimate of the ozone impacts from the facility. Therefore, even though originally Nucor's impacts were compared to an ozone standard of 80 ppb (due to a slight underperformance in the model), comparison to the 75 ppb standard would likewise yield insignificant impact.

VII. Responses to Comments Provided at the Public Hearing Held on Tuesday, December 28, 2010

These comments are taken from statements submitted at the public hearing on December 28, 2010 at the St. James Parish Courthouse. Comments addressing the same issue have been grouped and summarized from the public hearing transcript.⁷⁷

Comment No. VI.1

I think you should consider the people in the facility, within the area of the facility.⁷⁸

Louisiana already suffers from extreme issues with air quality. People's health are constantly being attacked from air quality problems that are generated by various petrochemical plants and/or industrial facilities.⁷⁹

I am opposed to passing an air permit like this that is likely going to cause the community's further health problems in the name of economic development. Louisiana is constantly ranked at the bottom, but we always reach for industrial areas that tend to

⁷⁷ See *Public Hearing on Proposed Initial Part 70 Air Operating and Prevention of Significant Deterioration Permit Permits and Environmental Assessment Statement for Consolidated Environmental Management, Inc., Nucor Steel Louisiana, Convent, St James Parish, Louisiana*, December 28, 2010 (EDMS Document No. EDMS Document No. 7788592), hereafter referred to as "*Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*."

⁷⁸ M. Cooper statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

⁷⁹ J. Dubinski statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

pollute us the most.⁸⁰

DEQ's job is to protect the health and environment of Louisiana. DEQ is not protecting the health and environment of Louisiana.⁸¹

It is just time for Louisiana to really think about jobs, good jobs. Clean jobs, not jobs that our children and our grandchildren and their grandchildren will be thinking about where is our asthma medication.⁸²

Nucor Steel proposes to emit various pollutants that threaten Louisiana health and welfare. For decades, the St. James Parish community has suffered the burdens of Louisiana's economic aspirations. How long is Louisiana going to put profits over the health and welfare of our communities?⁸³

I am concerned about high benzene emissions from the pig iron plant, from the proposed pig iron plant, and various other harmful emissions.⁸⁴

LDEQ Response to Comment No. VI.1

The emissions from this proposed project shall be controlled to meet or exceed the requirements of all applicable regulations and defined permit conditions. The estimated emissions submitted by Nucor for its emission sources are based on conservative engineering design calculations and established, approved emission factors.⁸⁵ In addition, Nucor's operations, under the terms and conditions of its permit, are expected to meet or exceed the requirements of the primary and secondary National Ambient Air Quality Standards (NAAQS) and Louisiana Ambient Air Standards (AAS). These standards are intended to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Also, the issue of the potential impact of Nucor's emissions is addressed in LDEQ's Basis for Decision.⁸⁶

The issue of balancing of environmental effects and economic benefits is addressed in the attached Basis for Decision.⁸⁷

Comment No. VI.2

All your technology that you have, you know, to stop all emissions, there are also humans that operate those things and there is likely for human error to happen at any given time.⁸⁸

⁸⁰ J. Dubinski statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

⁸¹ D. Malek-Wiley statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

⁸² D. Malek-Wiley statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

⁸³ J. Maeha statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

⁸⁴ J. Maeha statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

⁸⁵ See Permit application Appendix C (EDMS Document No. 6952414)

⁸⁶ Basis for Decision for the DRI Facility, Section IV.D

⁸⁷ Basis for Decision for the DRI Facility, Section IV.E

⁸⁸ M. Cooper statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*,

LDEQ Response to Comment No. VI.2

The LDEQ has conducted a review of all application-related materials, including the EAS (responses to the “IT Questions”) with regard to accidental spills or releases and has not found them to be inaccurate or inadequate.⁸⁹ Nucor has provided all information as requested by the LDEQ or as required as part of the permit decision making. In addition, Nucor’s EAS and other submitted information describe preventive measures such as structural controls, best management practices (BMPs) and the development and implementation of a Storm Water Pollution Prevention Plan (SWPPP) to address such circumstances.⁹⁰ Further, Nucor’s EAS, as accepted by the LDEQ, describes the issue of potential for unregulated emissions, along with its preventive measures to reduce the potential for such emissions.⁹¹

Nucor is also required to develop and maintain a Risk Management Plan (RMP). According to the EPA, the purpose of a Risk Management Plan (RMP) is to “prevent accidental releases of substances that can cause serious harm to the public and the environment.” The RMP is required to include a worst case scenario response plan. This issue is described further in the attached Basis for Decision document.⁹²

Comment No. VI.3

We don’t want to stop progress for the region or the parish. But our community should be relocated, so we don’t suffer the negative effects of the existing and future air pollution in the parish.⁹³

If you build the plant, let me move. Pay for my relocation. Nucor knows what we are going to encounter.⁹⁴

LDEQ Response to Comment No. VI.3

Relocation of the residents is not within the purview of the LDEQ’s actions on Nucor’s air permit application and proposed permit. This *Response to Comments* document addresses comments submitted from the public regarding the subject matter upon which the LDEQ invited comment.

Comment No. VI.4

We request that Nucor’s president and employees come and sit at the table and discuss solutions to the problems in the community, surrounding industry. And surrounding industry is welcome to join us.⁹⁵

December 28, 2010 (EDMS Document No. 7788592)

⁸⁹ See EAS (EDMS Document No.6952414, pp. 187-226 of 427)

⁹⁰ See EAS, (EDMS Document No. 6952414, pp. 192-193 of 427)

⁹¹ See EAS, (EDMS Document No. 6952414, pp. 195-196 of 427)

⁹² Basis for Decision for the DRI Facility, Section IV.D.1.c.

⁹³ B. Hasten statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

⁹⁴ J. Dubinski statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

⁹⁵ B. Hasten statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

LDEQ Response to Comment No. VI.4

The comment fails to disclose the particular issue upon which the comment is made.

Comment No. VI.5

Since there are separate permits for the pig iron plant and the DRI Plant, we are really not sure what the emissions are or what the total effects on the community are going to be.⁹⁶

Why are there separate permits for what is supposed to be an integrated facility? Why aren't the DRI and plant permitting emissions being considered together? The state is supposed to do this; the EPA has required it since 1985. The changes proposed by Nucor should be considered in one permit application so the entire permit's effects can be considered.

Nucor is hoping to avoid full national air quality ambient standards and construction permit analysis for the plant as a whole. LDEQ should require a single permitting process for both processes if Nucor continues to want to build the pig iron plant. How can we understand the effect on our health when it's not really clear what is being built? Is it DRI, pig iron, or a combination of both?⁹⁷

Nucor should submit the Environmental Assessment Statement that reflects the entire facility-the pig iron plant and the DRI facility.⁹⁸

LDEQ Response to Comment No. VI.5

Nucor intends to construct and operate both a pig iron plant and a DRI facility. These are separate operations with separate permits. The pig iron facility's proposed modification to its current permit (Permit No. 2560-00281-V0, issued May 24, 2010) is not intended to "reauthorize" construction of the pig iron manufacturing facility. Permit Nos. 2560-00281-V0 and PSD-LA-740 remain effective until modified and authorize Nucor to construct and operate the emissions units described therein, subject to the prescribed emissions limitations, monitoring requirements, and other conditions.

As detailed in the Basis for Decision associated with the initial Title V and Prevention of Significant Deterioration (PSD) permits for the site, LDEQ has already determined that the pig iron manufacturing facility, as originally permitted, "will not cause air quality impacts that will adversely affect human health or the environment in St. James Parish or in the surrounding parishes."⁹⁹ Further, LDEQ concluded that permits "minimized or avoided potential and real adverse environmental impacts to the maximum extent possible and that social and economic benefits of the proposed Nucor facility outweigh adverse environmental impacts."¹⁰⁰

⁹⁶ P. Vance statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

⁹⁷ P. Vance statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

⁹⁸ J. Maeha statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

⁹⁹ Basis for Decision for the DRI Facility, Section VI

¹⁰⁰ Basis for Decision for the DRI Facility, Section IV.E

The proposed modification for the pig iron facility permit will result in substantial reductions in emissions of criteria pollutants.

Nucor's application and related submitted information for its DRI facility has been examined by the LDEQ. The attached Basis for Decision document addresses the issues of alternative projects¹⁰¹ and avoidance of adverse environmental effects.¹⁰²

See response to Comment No I.1. See also response to Comment No. V.A.2 for the issue of aggregation of emissions.

Comment No. VI.6

Nucor estimates the levels of ammonia emissions associated with the DRI plant will increase over 500 percent to over 107 times[tons] per year.¹⁰³

We ask for the LDEQ to withdraw the permit for Nucor's pig iron plant.¹⁰⁴

The pig iron modifications will significantly increase toxic air pollutants, like ammonia. The DRI plant is certainly cleaner than the pig iron facility. The proposed DRI plant will emit only 1100 tons of pollutants, whereas the same size pig iron plant permitted today will emit 37,935 tons of pollutants. It's possible for Nucor to use cleaner technology to create jobs and boost the economy. It should not build a facility that poses risks to the communities that they will build in.¹⁰⁵

LDEQ Response to Comment No. VI.6

The pig iron plant proposed permit modification is a separate permit action from the DRI plant proposed permit.

The following is relevant to the emissions associated with Nucor's DRI plant operations. At the state level, Louisiana has established Ambient Air Standards (AAS) for a group of compounds known as Toxic Air Pollutants (TAP). TAPs include the federally-regulated Hazardous Air Pollutants (HAP), as well as a handful of other compounds such as ammonia and hydrogen sulfide. The impact of TAP emissions associated with DRI facility operations, under the terms and conditions of its permit, are expected to be below their respective AAS established by LAC 33:III.Chapter 51.

Modeling demonstrates that emissions from the facility will not violate National Ambient Air Quality Standards (NAAQS) for criteria pollutants and Louisiana AAS for toxic air pollutants.¹⁰⁶ Therefore, the facility will not cause air quality impacts which could adversely affect human health or the environment.

¹⁰¹ Basis for Decision for the DRI Facility, Section IV.B

¹⁰² Basis for Decision for the DRI Facility, Section IV.D

¹⁰³ P. Vance statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹⁰⁴ P. Vance statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹⁰⁵ J. Maeha statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹⁰⁶ Basis for Decision for the DRI Facility, Section IV.D.1.b.ii.

See Response to Comment No 5.

Comment No. VI.7

We ask for the LDEQ to provide the citizens of Louisiana an additional 45 days until February 15th of 2011 to analyze and submit comments.¹⁰⁷

There are 13,000 pages. At least extend the comment period until February 15th. We have a right to know.¹⁰⁸

LDEQ Response to Comment No. VI.7

Notice of the proposed permits was first published on November 24, 2010 and the comment period closed on January 3, 2010. Thus, the LDEQ has provided 39 full days for public review and comment, 9 days longer than required by regulation, in consideration of the holiday season. Therefore, the comment period will not be extended.

Comment No. VI.8

We want all the workers unionized and the construction which is not right to work, which is not DEQ's purview.¹⁰⁹

LDEQ Response to Comment No. VI.8

Unionization of workers is not within the purview of the LDEQ's actions on Nucor's air permit application and proposed permit. This *Response to Comments* document addresses comments submitted from the public regarding the subject matter upon which the LDEQ invited comment.

Comment No. VI.9

We are seeing a rush to use Go-Zone Bond money. Go-Zone Bond money was to help us recover from Hurricane Katrina. What does a steel plant in St. James Parish have to do with the folks that live on the coast of Louisiana that are still devastated by Louisiana?¹¹⁰

LDEQ Response to Comment No. VI.9

Funding is not within the purview of the LDEQ's actions on Nucor's air permit application and proposed permit. This *Response to Comments* document addresses comments submitted from the public regarding the subject matter upon which the LDEQ invited comment.

Comment No. VI.10

¹⁰⁷ P. Vance statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹⁰⁸ D Malek-Wiley statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹⁰⁹ D Malek-Wiley statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹¹⁰ D Malek-Wiley statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

You put out the notice for the permit on Thanksgiving Day. You have us here three days after Christmas, and you want the comments on January 3rd. You know, this sounds like a snow job. We have heard that it's almost like a bait and switch. Is it pig iron? Is it DRI?¹¹¹

LDEQ Response to Comment No. VI.10

See Responses to Comment No. 5 and No. 7.

Comment No. VI.11 (Summary of Statements Expressing Support for Nucor)

I feel our community will be very excited to have Nucor as an industry neighbor.¹¹²

Nucor's balanced attention to the well being of its Customers, Employees, Shareholders, Communities, and the Environment sets it apart from its competitors.¹¹³

Many of Nucor's steel facilities have received external environmental and chemical safety awards. Nucor's proven track record in environmental compliance, their commitment to research and investing in new technologies that further reduce greenhouse gas emissions is why I am confident in Nucor's commitment of protecting the environment in which they operate here. I support Nucor's request for these permits to operate here in St. James Parish and respectfully request the Louisiana DEQ to grant approval.¹¹⁴

I am here tonight as a representative of the St. James Parish Council. I am in full support of this project. As I stated in the past hearings, this is the kind of project that we want in St. James Parish. This is a very, very well respected company. It means a lot of jobs for St. James Parish. And if you want something to come into this parish as far as heavy industrial industries is concerned, this is the type project that you want.¹¹⁵

I am in favor of Nucor because it reduces the greenhouse gases. Nucor will only put out 896 tons per year of greenhouse gases compared to one tugboat and one tanker, which puts out more than 1700 tons per year. So one tugboat and one tanker which you see out there in the Mississippi river puts out twice as much emissions in a year as the DRI facility is going to put out. Also, they are bringing jobs to the community. And they are also reaching out and talking to the community, community leaders and people who live inside the community and make it a better place for people to live. I am in support of Nucor because Nucor sits and they actually talk to the people and come out to each and everyone. We also need the jobs and the infrastructure that it will bring us. So I do support Nucor.¹¹⁶

¹¹¹ D Malek-Wiley statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹¹² Councilman Wilson Malbrough written statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹¹³ P. Aucoin written statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹¹⁴ J. Amato statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹¹⁵ E. Bocz statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹¹⁶ R. Anry statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*,

This is my third time I have come before a group like this to speak in support of the necessary permits for Nucor. From the economic development point of view, it's a no brainer. For the record, the board that I chair is composed of 19 citizens throughout the parish. It's a cross-section of men and women, young and old, black and white, male and female. And we unanimously and continuously unanimously approve this project. It's jobs, jobs and jobs. That's what we need a lot of here in St. James Parish. Another thing that we favor about this particular company is that it's a large number of jobs which will be phased in. It gives the parish an opportunity to prepare for the influx of people that they hope will locate here and work here in addition to the people that are already here. So we wholeheartedly endorse this project. This company has record for being a good corporate citizen. They have a record of paying their employees well. It's the type of company that anybody who does economic development looks for and hopes for. Having said that, I would like to introduce again into the record the resolution adopted by the Board on March 31st, 2010. Also, I have a letter here for support from Councilman Brazan, who could not be here to tonight, but offers his full support for this facility.¹¹⁷

The jobs that Nucor will bring to the St. James Parish, as well as other industries that may locate adjacent to Nucor, are vitally needed for the growth of our parish, our region, our state.¹¹⁸

The Port of South Louisiana, supports the State of Louisiana, the Parish of St. James and all the people who want this facility which will be of great asset to St. James, to Louisiana and to the United States of America. Let me tell you that we in America need to look very carefully at making sure that we maintain our manufacturing phase. This will be a great asset to this area and will change the face of St. James Parish. I understand there are 900 people that are currently unemployed. We need to make sure that this company locates right here in St. James Parish and that it provides the opportunity for our young people who want to work to make an average salary of \$75,000.00 a year. That is more than three times their average median income of some of the people in this particular area.

You are going to see a facility here that will invest five or six billion dollars in your community. I know that we can trust this corporation. I know that public officials of St. James Parish do. The people that you heard speak on behalf of St. James Parish and this facility and Nucor, they do likewise support Nucor. Let's go ahead and get this permit, and let's get it moving quickly. America needs to be in a position to provide jobs for its people. America needs to be in a position to defend itself, if necessary, and this is the basics. This is where you start. So all of you that may have some doubt, I urge you to reconsider. I urge some of the neighbors that may have some doubt to reconsider this facility, and let's support it. It's needed in St. James. It's needed in Louisiana. And it's certainly needed by the United States of America.¹¹⁹

I am also a member of the St. James Parish Economic Development Board and past president of the River Region Chamber of Commerce and still a member of the River Region Chamber of Commerce. And tonight I am here on behalf of the 270 businesses that represent the River Region and the 14,000 employees in the region area that support Nucor Steel located in St. James

December 28, 2010 (EDMS Document No. 7788592)

¹¹⁷ P. Aucoin statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹¹⁸ J. Brazan written statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹¹⁹ J. Chaisson statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

Parish. It will benefit the area. Our local businesses will benefit from that, and we are in full support.¹²⁰

I own a company called Quality Machine Works. I have been in business 25 years. I am in favor of Nucor locating in our parish. I am in favor of this project because of jobs. We have a lot of good people in St. James Parish. Maybe we have a lot of middle-class people, and we have a lot of poor people. I am for helping the poor. The first time I met the Nucor officials with our parish president, I kind of like what he had to say when he said, "I believe in this, too." It hadn't happened in this parish since 1968 where a company said we will come in and take an average individual, like myself, a high school graduate, take an average, hard working individual, somebody who is dedicated to a job and train them to be the person that they need for their particular job. I am excited about that. We have a lot of poor people that need a better opportunity to raise their family, educate their family and build homes.¹²¹

I am a resident of St. James Parish. I kind of get disturbed because I have been involved in the industry for over 35 years, and I have worked in the environmental arena, most of my work. I got started in Kaiser in '75 as a technician in the Environmental Department. And throughout the many years that I have worked in the Environmental Department, I have actually gone up the ladder to different levels. The guy mentioned tonight almost a 200 percent reduction in the toxic air pollutants. I don't understand why we are opposing this project. People perish for the lack of knowledge. Often times you get opposition from people in the environmental arena that I guess will bring issues to the parish, to community that they can pride upon and give them information that is not concrete. And that disturbed me. Because 21 years ago, Syntec was trying to locate in St. James Parish. They were opposed. They left. They went to Plaquemine and are doing rather well. Formosa 21 years ago was going to locate in St. John Parish in Edgard. There was some opposition. They built in Taiwan. But yet, still the most affluent neighborhoods that we have, like St. Amant, was built as a result of the Shell Motiva facility. And it disturbed me because the opposing team comes in, and they come in as a team to bring information to a neighborhood that is totally unaware of what is going on. One guy mentioned the emission rate of a tugboat is much more what these guys are going to put out. You have tugboats, and you have these vessels waiting to be unloaded. We have no earthly idea what's being emitted. From an environmental perspective, I can assure you that Nucor will not have an issue with emissions. Reviewing tonight is enough to tell me that anybody opposing the project is opposing for lack of knowledge. I totally support Nucor in their efforts to build in St. James Parish.¹²²

I came here with some information that we had received in the email about the emissions were going to be, and I came here to find out. I have to say that the information I got was wrong. It looks like the permit that they are applying for is a whole lot better than anything I had seen. You know, I believe in that kind of development, I know how important it is. I know that every job that comes in creates two or three other smaller jobs in our community. I have to say I am in complete support of this from everything I have learned tonight. The potential good that a project like this can do for your community here in St. James and reach all the way over to us across the river because it's huge, it could be fantastic for all of us. I have been persuaded to be in support of the project completely. My concerns were addressed. And that is what is supposed

¹²⁰ B. Gravois statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹²¹ D. Louque statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹²² L. Bailey statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

to happen.¹²³

I support Nucor. Give it a chance. Jobs and opportunity will come. Health wise, we are not making oxy, zeno. Those are already here. So give them a chance. Then we can relocate with money with a better paying job. If we give them an opportunity to give us an opportunity, hold them accountable for their action. I am in support of Nucor.¹²⁴

LDEQ Response to Comment No. VI.11

The LDEQ has reviewed these comments, as well as all other comments addressed in this document, as part of its review of the Nucor permit application. The LDEQ appreciates the input provided by all commenters during the public comment process.

VII. Responses to Comments Submitted by the Zen-Noh Grain Corporation dated January 3, 2011¹²⁵

LDEQ Introduction

Throughout these comments, the commenter suggests that LDEQ's BACT determinations do not represent the "maximum degree of reduction." With few exceptions, the commenter does not dispute the technology selected as BACT, but the performance level (i.e., emissions limit) achievable by that technology. At the onset, it is imperative to understand how BACT emissions limits are derived. It is not appropriate to establish an emissions limit based on the theoretical or maximum predicted efficiency of a control device. The NSR Manual states (at pp. B-23 – B-24):

The objective of the top-down BACT analysis is to not only identify the best control technology, but also a corresponding performance level (or in some cases performance range) for that technology considering source-specific factors. Many control techniques, including both add-on controls and inherently lower polluting processes can perform at a wide range of levels. Scrubbers, high and low efficiency electrostatic precipitators (ESPs), and low-VOC coatings are examples of just a few. It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options. **Rather, the applicant should use the most recent regulatory decisions and performance data for identifying the emissions performance level(s) to be evaluated in all cases.**

The EPA does not expect an applicant to necessarily accept an emission limit as BACT solely because it was required previously of a similar source type. While the most effective level of control must be considered in the BACT analysis, different levels of control for a given control alternative can be considered. For example, the consideration of a lower level of control for a given technology may be warranted in cases where past decisions involved different source types. The evaluation of an alternative control level can also be considered where the applicant can demonstrate to the satisfaction of the

¹²³ A. Tassin statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹²⁴ R. Williams statement, *Public Hearing for Proposed Part 70 and PSD Permits and EAS for Nucor Steel Louisiana*, December 28, 2010 (EDMS Document No. 7788592)

¹²⁵ EDMS Doc ID 7789229

permit agency demonstrate that other considerations show the need to evaluate the control alternative at a lower level of effectiveness.

Manufacturer’s data, engineering estimates and the experience of other sources provide the basis for determining achievable limits. Consequently, in assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative.

(Emphasis added.)

Moreover, EPA’s Environmental Appeals Board (EAB) has had occasion to address this issue in several past PSD cases and has acknowledged that permitting agencies have discretion in determining whether a particular control efficiency level is appropriate in determining BACT and in setting an appropriate emissions limit. The EAB has found that:

When [a permit issuer] prescribes an emissions limitation representing BACT, the limitation does not necessarily reflect the highest possible control efficiency achievable by the technology on which the emissions limitation is based. Rather, the [permit issuer] has discretion to base the emissions limitation on a control efficiency that is somewhat lower than the optimal level. * * * There are several different reasons why a permitting authority might choose to do this. One reason is that the control efficiency achievable through the use of the technology may fluctuate, so that it would not always achieve its optimal control efficiency. * * * Another possible reason is that the technology itself, or its application to the type of facility in question, may be relatively unproven. * * * To account for these possibilities, a permitting authority must be allowed a certain degree of discretion to set the emissions limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the permittee to achieve compliance consistently.¹²⁶

[P]ermit writers retain discretion to set BACT levels that “do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis.” *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 188 (EAB 2000); *accord In re Three Mountain Power, L.L.C.*, 10 E.A.D. 39, 53 (EAB 2001). In particular, we have approved the use of a so-called “safety factor” in the calculation of the permit limit to take into account variability and fluctuation in expected performance of the pollution control methods. *See, e.g., Knauf II*, 9 E.A.D. at 15 (“There is nothing inherently wrong with setting an emissions limitation that takes into account a reasonable safety factor.”). As we noted in *Masonite*, where the technology’s efficiency at controlling pollutant emissions is known to fluctuate, “setting the emissions limitation to reflect the highest control efficiency would make violations of the permit unavoidable.” 5 E.A.D. at 560.¹²⁷

In the same decision, the EAB also stated that:

In essence, Agency [EPA] guidance and our prior decisions recognize a distinction between, on the one hand, measured “emissions rates,” which are necessarily data

¹²⁶ *In re: Newmont Nevada Energy Investment, L.L.C., TS Power Plant, PSD Appeal No. 05-04, December 21, 2005, pg. 43.*

¹²⁷ *Ibid.*

obtained from a particular facility at a specific time, and on the other hand, the “emissions limitation” determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility’s life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the “emissions limitation” that is “achievable” for that pollution control method over the life of the facility. Accordingly, because the “emissions limitation” is applicable for the facility’s life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term. Thus, the permit issuer may take into account the absence of long term data, or the unproven long-term effectiveness of the technology, in setting the emissions limitation that is BACT for the facility. *Masonite*, 5 E.A.D. at 560 (noting that the permit issuer must have flexibility when “the technology itself, or its application to the type of facility in question, may be relatively unproven”).

As recommended by EPA, LDEQ has looked to the most recent regulatory decisions (e.g., data in EPA’s RACT/BACT/LAER Clearinghouse), manufacturer’s data, engineering estimates, and the experience of other sources, to the extent such data is available, in determining BACT.

Comment No. VII.1

Permitting construction of the pig iron and DRI manufacturing processes as separate projects unlawfully circumvents the requirements of Title I of the Clean Air Act. Title I, Part C of the Clean Air Act (“Prevention of Significant Deterioration”), 42 U.S.C. §§ 7470-7477, and regulations promulgated to implement Title I, including 40 C.F.R. §§ 51.165 & 52.21 and LAC 33:III.509 (collectively, “PSD”), provide that a permit for construction of a major source of air pollutants may be issued only upon a demonstration that potential emissions from construction or operation of the source will not cause or contribute to a violation of any national ambient air quality standard (“NAAQS”) or PSD increment. *See, e.g.*, 42 D.S.C. § 7475(a)(3). PSD also requires “an analysis of any air quality impacts projected for the area as a result of growth associated with [the] facility.” 42 U.S.C. § 7475(a)(6). These requirements are incorporated in the Louisiana state implementation plan (“SIP”), which requires the applicant to demonstrate that allowable emissions from a proposed source, in conjunction with all other applicable emissions increases or reductions and secondary emissions, will not cause or contribute to a violation of any NAAQS or PSD increment. *See* LAC 33:III.509.K. The air quality impact analysis must be made available for public review and comment at the public hearing on the application. 42 U.S.C. § 7475(a)(2) & (e)(3)(C). Moreover, the operating permit program under Title V of the Clean Air Act, 42 U.S.C. § 7661a-7661f, and regulations promulgated pursuant to Title V, including 40 C.F.R. Part 70 and LAC 33:III.507 (collectively, “Part 70”), does not authorize a source or permit authority to circumvent the requirement to provide an air quality impact analysis for public review and comment *See Sierra Club v. Dairyland Power Coop.*, No. 10-cv-303-bbc, 2010 U.S. Dist. LEXIS 112817 (W.D. Wis. Oct. 22, 2010) (holding that a citizen suit alleging failure to comply with BACT and air quality impact analysis requirements under PSD is not a collateral attack on the facility’s Part 70 permit).

EPA has identified a number of factors that should be considered to determine whether two projects or sources should be aggregated for preconstruction permitting purposes. A primary factor to consider is whether the permit applications are submitted simultaneously or within a short period of time. *See* John B. Rasnic, “Applicability of New Source Review Circumvention Guidance to 3M-Maplewood, Minnesota,” June 17,

1993 (“Maplewood Memo”). When a company submits two preconstruction permit applications for a site within an 18-month span, EPA considers this to be strong evidence of an intent to circumvent the full scope of preconstruction review. *Id.* The same is true when the second application is submitted before construction of the initial project commences. “An application for a change to an application or permit for a source not yet in operation would generally prompt reanalysis of the proposed project as if the original application had been submitted in that form.” Revised Policy on Permit Modifications and Extensions, July 5, 1985 (the “1985 Policy”), pp. 8-9, and 13. These changes should be “handled as part of the initially permitted project, rather than as new projects.” *Id.*, p. 9. The basis for this policy is EPA’s concern that otherwise a source would not be subject to the full review required by PSD, including BACT, air quality impact analysis and public participation. *Id.*, pp. 9, 14-15. The proposed change may require revision to the existing analyses and, in some cases, performance of new analyses. *Id.*, p. 14. “The criteria for requiring additional review elements will be whether the original new source or major modification application underwent all of the review which would have applied had the application been submitted in its revised form originally.” *Id.*

Other factors that evidence an intent to circumvent PSD review, and thus indicating that two sources should be aggregated for preconstruction permitting purposes, include: (1) statements by representatives of the source about the source’s plans for operation, see Maplewood Memo; (2) whether managers or workers will be shared between the facilities, Richard R. Long, “Response to Request for Guidance in Defining Adjacent with Respect to Source Aggregation,” May 21, 1998 (“Long Memo”); (3) whether the location of the new facility chosen primarily because of its proximity to the existing facility, to enable the operations to be integrated; (3) whether materials will be routinely transferred between the facilities, *id.*; and (4) whether one facility will produce a product that requires further processing at the other facility, *id.* (finding that two noncontiguous foundries should be aggregated for PSD purposes because all the casting from both foundries were coated, packaged and shipped at one of the foundries); see also Cheryl L. Newton to Donald Sutton, March 13, 1998 (finding that two facilities -- one consisting of a coke oven and blast furnace, and the other of a basic oxygen furnace and strip mill -- should be aggregated for PSD purposes even though they were separated by Lake Calumet, landfills, I-94 and a river, because of their “close proximity of the sites, along with the interdependency of the operations and their historical operation as one source”). All these factors evidence the intent to circumvent the air quality impact analysis requirements for the pig iron and DRI manufacturing processes. The pig iron PSD permit was resubmitted (in substantially revised form) in June 2009. See EDMS Doc. 47485821 (the “Basis for Decision”). The DRI permit application was submitted 14 months later, in August 2010. Construction of the pig iron plant had not commenced when the DRI application was submitted and, in fact, has not commenced yet. Then, in October 2010 -- two months after submitting the DRI permit application -- Nucor submitted an application to make a major modification to the pig iron process. This modification, which will include elimination of a blast furnace and addition of selective catalytic reduction (“SCR”) control technology on NO_x sources in the pig iron process, will reduce NO_x emissions from the pig iron process but in return will cause a very significant increase in sulfuric acid mist (“SAM”) emissions. According to Nucor, it is proposing to undertake this modification for the sole purpose of maintaining the viability of the overall Nucor Steel Louisiana project. This chain of events illustrates that the DRI and pig iron processes are intertwined.

In addition to the temporal factor, both processes will be owned and operated by Consolidated Environmental Management, Inc. (a subsidiary of Nucor) and located on

the same property in Convent. See EDMS Doc. 7731641, pp. 372, 378; EDMS Doc. 7731649, pp. 404, 409. John Farris will be the on-site manager and Jeff Braun will be the on-site contact for air pollution control for both processes. Id. Operation of both processes will share the use of several emission sources, including paved (FUG-102) and unpaved roads (FUG-101), the iron oxide loading/unloading gantry crane (DOC-101), raw material conveyors (FUG-103), iron oxide storage piles (PIL-102), the sinter plant (SIN-101), and the service water system. All paved roads will be considered part of the “DRI permit” and all unpaved roads will be considered part of the “pig iron permit” regardless of whether the paved or unpaved roads are physically located within the battery limits of those processes. All raw materials and product conveyed to or from the mass storage piles will be considered part of the “DRI permit” regardless of which process used or generated the raw material or product. In fact, since there will not be a conveyor fugitive emission source in the “pig iron permit,” even emissions from conveying pig iron will be permitted as part of the DRI process. The same holds for iron oxide raw material storage -- it is all permitted as part of the DRI process even if it will be used to produce pig iron.

Last, Nucor's official statements make it absolutely clear that Nucor considers the DRI and pig iron processes to be part of a single operation. During an October 21, 2010 earnings call, Nucor's chairman, Dan Damico, clarified Nucor's position that the DRI process is really just an extension of the pig iron plant, stating:

Actually we do mean both. Let me clarify it for you. All along, we've said there were three phases to the project. The first phase was a 3 million ton a year blast furnace/coke oven, second phase was a 3 million ton a year blast furnace/coke oven, and the third phase would be potentially steel making operations and downstream activities. So what we are talking about changing is only the first phase. The other two phases are still permitted and is intact and will depend upon conditions at the time that we decide to act on the second phase. In the first phase, instead of being just one blast furnace and coke oven, it is now being permitted for two DRI plants of 2.5 plus million tons a piece.

See Nucor CEO Discusses Q3 2010 Results - Earnings Call Transcript ("Earnings Call"), available at: <http://seekingalpha.com/article/231532-nucor-ceo-discusses-q3-2010-results-earnings-call-transcript?part=qanda>.

Clearly, the DRI and pig iron processes are simply phases of a single project. Zen-Noh and the public have been harmed by the issuance of separate PSD permits for this multi-phase project. It is not enough separately to evaluate the air quality impacts of the phases because, as explained more fully in comments to follow, the “phased” air quality impact analysis approach allowed Nucor to avoid performing a full air quality impact analysis for PM₁₀, PM_{2.5}, SO₂, and CO (not to mention certain hazardous air pollutants and toxic air pollutants). If Nucor is required to evaluate the impacts of the aggregate emissions from the DRI and pig iron processes, a full air quality impact analysis will be (and is) required for all regulated new source review (“NSR”) pollutants. EPA and the public will then have an opportunity to review and comment on the true impacts of Nucor's overall plan for Convent.

This is nothing more and nothing less than what the Clean Air Act requires. The air quality impact demonstrations for a proposed source must be based on the potential emissions, i.e., the emission rate at the maximum operating capacity of the source, taking

account for operating or production limits and controls only if they are federally enforceable. See New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting,” Draft, October 1990 (the “NSR Manual”, p. C.II. This emission rate must “comport with the true design and intended operation of the project.” Terrell E. Hunt, “Guidance on Limiting Potential to Emit in New Source Permitting,” June 13, 1989 (“Hunt Memo”), p. 13. As noted by Mr. Damico, the true design and intended operation for the Nucor Steel Louisiana facility is to produce at least 8 million tons per year (“tpy”) of iron feedstock for Nucor’s steel mills -- 3 tpy of pig iron and 5 tpy of DRI -- not the 6 tpy of pig iron reflected in the pig iron PSD permit or the 5 tpy of DRI reflected in the DRI PSD permit. Nucor has a duty to provide -- and the public has a right to review and comment on -- the true air quality impacts of Nucor’s plans. Permit Nos. PSD-LA-740 and 2560-00281-V0 authorizing construction of the pig iron manufacturing plant should be terminated and the proposed DRI Permits should be withdrawn. The pig iron and DRI manufacturing plants must be permitted under a single PSD permit, and the public must be given an opportunity to review and comment on the aggregate emissions and air quality impacts from the pig iron and DRI manufacturing processes, pursuant to § 165 of the Clean Air Act.

LDEQ Response to Comment No. VII.1

See LDEQ Response to Comment No. V.A.2.

Comment No. VII.2

The Permit No. PSD-LA-751 violates 42 U.S.C. § 7475(a) and should be withdrawn and re-issued, for public review, with sufficient support to demonstrate that LDEQ has fulfilled its responsibility to assure that “the proposed facility is subject to the best available control technology for each pollutant subject to regulation ... that is emitted from, or which results from, such facility.” One of the principal requirements of PSD is that the source must install and operate state-of-the-art pollution controls, known as best available control technology (“BACT”) for each regulated NSR pollutant. *See* 42 U.S.C. § 7475 (a)(4). BACT is defined as:

- a.) an emissions limitation, including a visible emission standard, based on the maximum degree of reduction for each pollutant subject to regulation under this Section that would be emitted from any proposed major stationary source or major modification that the administrative authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant;
- b.) in no event shall application of *best available control technology* result in emissions of any pollutant that would exceed the emissions allowed by an applicable standard under 40 CFR Parts 60 and 61. If the administrative authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of *best available control technology*. Such' standard shall, to the degree possible, set forth the emissions reduction

achievable by implementation of such design, equipment, work practice, or operation, and shall provide for compliance by means that achieve equivalent results.

LAC 33:III.509.B; *see also* 42 U.S.C. § 7479(3).

To ensure that the BACT determination is “reasonably moored” to the Clean Air Act’s statutory requirement that BACT represent the maximum achievable reduction, EPA has established a top-down analysis process that is described in the NSR Manual; *see Alaska Dept. of Env’t Conservation v. Env’t Protection Agency*, 540 U.S. 461, 485 (2004). LDEQ’s standard practice and policy is to follow the top-down BACT procedure described in the NSR Manual. *See* Louisiana Guidance for Air Permitting Actions, Louisiana Department of Environmental Quality, Feb. 26, 2008 (“LDEQ Permit Manual”), pp. 91-92; *see also* Public Comments Response Summary (“Response to Comments”) issued in support of PSD Permit No. PSD-LA-740, EDMS Doc. 47485821, pp. 91-95, 101 and 105. This approach is widely used by permitting agencies and EPA to make BACT determinations, *See, e.g., In re Northern Michigan University Ripley Heating Plant*, PSD Appeal No. 08-02 (E.A.B., Feb. 18, 2009) (remanding a PSD permit because the applicant’s BACT analysis did not conform to top-down approach required by the NSR Manual); *In re Inter-Power of New York, Inc.*, 5 E.A.D 130 (E.A.B. March 16, 1994); *In re Masonite Corp.*, 5 E.A.D. 551 (E.A.B., Nov. 1, 1994).

LDEQ’s analyses do not satisfy the definition of BACT and the top-down BACT process for numerous reasons including: (1) failure to document BACT decisions; (2) failure to evaluate all control options; (3) failure to require the BACT control technology in the draft permits; (4) failure to establish a BACT emission limitation; (5) failure to establish enforceable conditions; (6) failure to establish averaging times; (7) failure to document the reason(s) proposed monitoring assures continuous compliance; and (8) omission of regulated PSD pollutants, among others.

The NSR Manual details the necessary process for determining “top-down” BACT, as required by 42 U.S.C. § 7475. As explained in Table B-1 of the NSR Manual, this five-step process is conducted to ensure that a valid BACT determination has been made:

- STEP 1: Identify all control technologies. This list must be comprehensive and include all lowest achievable emission rates (“LAER”).
- STEP 2: Eliminate technically infeasible options. A demonstration of technical infeasibility should be clearly documented and must show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.
- STEP 3: Rank remaining control technologies by control effectiveness. This includes:
 - control effectiveness (percent pollutant removed);
 - expected emission rate (tons per year and pounds per hour);
 - expected emission reduction (tons per year);
 - energy impacts;
 - environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
 - economic impacts (total cost effectiveness, incremental cost effectiveness)

- STEP 4: Evaluate most effective controls and document results. This must include a case-by-case consideration of energy, environmental, and economic impacts. If top option is not selected as BACT, evaluate next most effective control option.
- STEP 5: Select BACT. The most effective option not rejected is BACT.

In a typical BACT process, the Applicant prepares an initial analysis that is submitted to the permitting agency. The agency reviews the analysis, requests additional information, conducts independent analyses, and makes an independent determination. A draft permit is then prepared based on the BACT analysis that is reviewed by the Applicant and the public. The permitting agency reviews and responds to comments received on its draft determination and issues a final BACT determination, which is subject to U.S. EPA's review and oversight.

Nucor's BACT proposal for sulfur dioxide ("SO₂"), nitrogen oxides ("NO_x"), particulate matter with an aerodynamic diameter of 10 micrometers or less ("PM₁₀"), particulate matter with an aerodynamic diameter of 2.5 micrometers or less ("PM_{2.5}"), carbon monoxide ("CO"), and volatile organic compounds ("VOC") is included in the DRI Application. Although the DRI Application was modified in three addenda, the BACT analyses for the DRI sources were not modified between the initial submittal in August 2010 and the issue of the draft PSD Permit in November 2010.

The DRI PSD Permit violates the BACT requirements in 42 U.S.C. §7475(a) and LAC 33:III.509. The permit contains BACT provisions in two places. LDEQ's top-down reviews and determinations of what should be BACT for the DRI plant are contained in the Preliminary Determination Summary, and the specific BACT requirements are set forth in the Specific Conditions section. For the most part, LDEQ's BACT analyses are cut and pasted from Nucor's DRI Application. Major sections are copied verbatim from Nucor's documents. This is inappropriate. To satisfy its obligations under 42 U.S.C. §7475, La. Rev. Stat. § 30.2018, and LAC 33:III.509, LDEQ may not simply rely upon the applicant's statement as to what should constitute BACT -- LDEQ must provide a "careful evaluation of all the consequences" of the decision to permit the DRI plant, 42 U.S.C. § 7470(5), and assure that the requirements for BACT will be met. To satisfy these requirements, LDEQ should withdraw and re-publish for DRI PSD Permit for public review and comment, with sufficient documentation to show that LDEQ has: (a) requested from Nucor or otherwise obtained technical support documentation to demonstrate that all available technologies have been evaluated, that technologies are not discounted as "technically infeasible" unless truly infeasible, and that technologies are not discounted as "economically infeasible" unless truly infeasible; (b) verified that accurate uncontrolled and controlled emission rates are evaluated for each feasible control technology; (c) established emission limitations and appropriate design criteria for each selected BACT; (d) established conditions to assure that each the control technologies selected will in fact provide continuous emission reductions in compliance with BACT; (e) verified that the BACT decisions in the Preliminary Determination Summary are accurately and completely reflected in the Specific Conditions is selected for each source; and (f) verified that each regulated NSR pollutant for each DRI source will be subject to BACT.

LDEQ Response to Comment No. VII.2

Because the comments rely heavily on statements from EPA's 1990 New Source Review Workshop Manual (NSR Manual), it is imperative to recognize that this document remains in "draft" form and was never formally adopted as guidance. In fact, the preface to the NSR Manual states, "It [the NSR Manual] is not intended to be an official statement of policy and

standards and does not establish binding regulatory requirements; such requirements are contained in the regulations and approved state implementation plans.”

Nevertheless, many people have looked to this document for guidance and have sometimes improperly construed the draft NSR Manual to contain requirements that must be followed. To avoid any misunderstandings concerning the effect of the NSR Manual, EPA has proposed to make clear that the manual is not a binding regulation and does not by itself establish final EPA policy or authoritative interpretations of EPA regulations under the NSR program.¹²⁸

The EPA’s Environmental Appeals Board (“Board”) has sometimes referenced the draft NSR Manual as a reflection of our thinking on certain PSD issues, but the Board has been clear that the draft NSR Manual is not a binding Agency regulation. *See*, In re: Indeck-Elwood, LLC, PSD Permit Appeal No. 03–04, slip. op. at 10 n. 13 (EAB Sept. 27, 2006); In re: Prairie State Generating Company, PSD Permit Appeal No. 05–05, slip. op. at 7 n. 7 (EAB Aug 24, 2006). In these and other cases, the Board also considered briefs filed on behalf of the Office of Air and Radiation that provided more current information on the thinking of the EPA headquarters program office on specific PSD issues arising in particular cases. Thus, the Board has looked to the draft NSR Manual as one resource to consider in developing Agency positions through case-by-case adjudications, while recognizing that the draft NSR Manual does not itself contain binding requirements.¹²⁹

Notably, it remains EPA’s *policy* to use the five-step, top-down process to satisfy the BACT requirements when PSD permits are issued by EPA and delegated permitting authorities, and EPA continues to interpret the BACT requirement in the CAA and EPA regulations to be satisfied when BACT is established using this process. However, notwithstanding this policy and the interpretations of the BACT requirement reflected in EPA adjudications, EPA has not established the top-down BACT process as a binding requirement through regulation. Nevertheless, LDEQ followed EPA’s suggested top-down process in this instance. As evidenced by Section IV.A of the Preliminary Determination Summary of PSD-LA-751, LDEQ detailed each of the five steps for each BACT determination made.

Further, the commenter has omitted material from the NSR Manual that does not support its allegation. On page B-11, the NSR Manual states, “The applicant should make a good faith effort to compile appropriate information from available information sources, including any sources specified as necessary by the permit agency. The permit agency **should review** the background search and resulting list of control alternatives presented by the applicant to check that it is complete and comprehensive” (emphasis added).

LDEQ conducted a thorough, independent review of the application materials. Because LDEQ directs applicants to apply the top-down approach to determine BACT and because, as explained above, LDEQ documents each step of this process in the Preliminary Determination Summary,¹³⁰ it is not surprising that the application materials and permit read similarly.

¹²⁸ Proposed “Prevention of Significant Deterioration New Source Review: Refinement of Increment Modeling Procedures,” 72 FR 31372, June 6, 2007

¹²⁹ 72 FR 31376 – 31377

¹³⁰ See “Louisiana Guidance for Air Permitting Actions” (pg. 91 of 181), available at <http://www.deq.louisiana.gov/portal/tabid/64/Default.aspx>.

The fact that an agency utilizes an applicant's BACT analysis language does not demonstrate that the agency has failed to conduct a BACT analysis. In this case, the applicant conducted an analysis of available technologies, which was not modified by any addenda to the application, and placed the discussion in substantially the format recommended, not required, by the NSR Manual. There is no statutory or regulatory requirement that LDEQ revise the language of an analysis that otherwise meets applicable requirements.

The comments are simply conclusory statements that the permit application and draft permit do not comply with statutory and regulatory requirements. The commenter has presented no evidence of any particular BACT analysis that does not meet the regulatory requirements of the Clean Air Act or its implementing regulations.

Comment No. VII.3

The BACT determinations in Permit No. PSD-LA-751 violate 42 U.S.C. § 7475(a) because they must be -- but are not -- supported by technical documentation that is available for public review and comment. A proper BACT determination must include both supporting factual documentation and a detailed discussion of the permit authority's decision-making process. *In re BP Cherry Point*, 12 E.A.D. 209,233 (E.A.B. 2005); *In re Newmont Nev. Energy Inv., L.L.C.*, 12 E.A.D. 429 (E.A.B. 2005); *In re Cardinal FG Co.*, 12 E.A.D. 153, 167-68 (E.A.B. 2005). An applicant bears the burden of demonstrating that a control option is either commercially unavailable or inapplicable to the project, that an available technology is technically infeasible, and that the selected control technology will actually achieve BACT. *In re Pennsauken County N.J., Res. Recovery Facility*, 2 E.A.D. 667, 672 (Adm'r 1988) ("The applicant's BACT analysis ... does not contain the level of detail and analysis necessary to satisfy the applicant's burden" of showing that a particular control technology is technically or economically unachievable."). This demonstration must include adequate technical documentation. *In re: Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 129-30 (E.A.B. 1999) ("*Knauf I*") at 131; *In re ConocoPhillips Co.*, PSD Appeal No. 07-02, slip op. at 34 (June 2, 2008) (permitting authorities must "sufficiently analyze and consider available technologies and techniques in order to adequately make a BACT determination, and in doing so; must gather the necessary information (whether directly or by requesting more information from the permit applicant) to ensure and document that statutory and regulatory obligations have been met"); Walter C. Barber, BACT Information for Coal-fired Power Plants, Dec. 22, 1978 (describing initial and follow-up technical information needed to establish BACT during the initial BACT review).

Obtaining technical support documentation -- and providing the documentation for public review and comment -- is always a necessary element of a permitting agency's BACT determination. It is even more important and necessary where, as here, there is a lack of readily-available technical literature describing the emission sources and the application of control technologies to the sources. Nucor has not decided what type of DRI process to construct, but even if it had, EPA has not developed AP-42 emission factors for either type of process and there are no corresponding units currently operating in the United States from which comparisons might be drawn. Nucor also has not decided what type of acid gas treatment system to construct, but suffice it to say that there is no public record of any such system ever being applied to a DRI facility in the United States. In sum, there is nothing in the record, or readily available to the public, that would enable LDEQ or Zen-Noh to evaluate Nucor's calculations of uncontrolled emissions, control efficiencies, and controlled emissions.

The necessary information must, however, be available to Nucor. According to Mr. Damico,

Nucor was in the midst of equipment discussions with several vendors in October 2010 and was looking at several technologies. *See Earnings Call*, pp. 10-11. Even if Nucor has not yet selected the DRI and acid gas vent cleaning vendors, Nucor could -- and should -- have provided the mass balances, design parameters, emission estimates and guaranties that Nucor *must* have obtained from the DRI, acid gas cleaning, and SCR vendors before committing to this project. The Clean Air Act requires that the public be given a fair opportunity to review and comment on the BACT proposed for a new major source, before the public hearing on a proposed PSD permit. 42 U.S.C. § 7475(a)(2). LDEQ should require Nucor to provide LDEQ an opportunity to review the technical documentation supporting the DRI BACT determinations and emission rates. LDEQ should make the technical support documentation available for public review and comment, re-publish the draft PSD permit (in the form of a single PSD permit for the aggregate pig iron and DRI production facility, as described in Comment No.1), and conduct another public hearing.

LDEQ Response to Comment No. VII.3

The bases for LDEQ's conclusions are adequately set forth in the permitting record and Preliminary Determination Summary. It is the responsibility of the applicant to provide detailed and accurate technical documentation with the air permit application. LDEQ reviews the documentation provided, as well as other informational sources, to ensure that the application materials are technically correct and meet regulatory requirements. This review often includes research to verify the information provided.

As explained previously, EPA's NSR Manual states, "The applicant should make a good faith effort to compile appropriate information from available information sources, including any sources specified as necessary by the permit agency. The permit agency **should review** the background search and resulting list of control alternatives presented by the applicant to check that it is complete and comprehensive" (page B-11, emphasis added).

The commenter suggests that the technical data submitted in the permit application is inadequate for the commenter's review, and that information on direct reduced iron facilities is not commonly available. The assumption that information from similar sources must be both common and available to the commenter would preclude the innovation of new technologies and processes, which is clearly not the purpose of the PSD program. The permittee is not required to submit a fully engineered plant for permitting purposes.

A DRI facility using the Midrex process was permitted recently in the United States. LDEQ carefully considered the conclusions and BACT determinations reached in that permit, differences in the proposed Nucor facility, and recent advances in technology in determining BACT for the proposed Nucor facility. For example, LDEQ considered the Mexican HYL process, which is not demonstrated for sources the size of the proposed Nucor facility. Because the HYL process is not demonstrated, LDEQ determined that the facility should be permitted based on the best available technology that is demonstrated, the Midrex process, as upgraded to meet more stringent controls suggested by Nucor and accepted by LDEQ as meeting BACT. The commenter has not provided any specific information demonstrating that any aspect of the facility does not meet BACT.

It should be noted that a plant of similar design was permitted by LDEQ, and subsequently constructed and operated within a mere two miles of the proposed facility, and as such LDEQ has experience with the process in question. Another plant of similar design was permitted by LDEQ in 1996, with virtually the same footprint as the Nucor DRI facility. The permit included a DRI facility using the Midrex process and a port designed with the same geometry and purpose as the Nucor port design. This facility was not constructed. The technical information that has been

available as presented by the applicant, previously permitted facilities, and through technical publications has not been lacking.

LDEQ has experience in permitting and inspecting amine-based absorption systems, particularly in regard to H₂S capture as will be performed at the DRI facility, and has no reason to believe that such a system applied to the DRI process would fail to achieve the represented operating standards. LDEQ does not require specific vendor selection or design drawings prior to reaching a final decision on air quality permits. It is the responsibility of the applicant to ensure that selected designs are fully capable of meeting the permit limits established by LDEQ.

In LDEQ's engineering judgment, adequate technical data were presented to allow reasonable estimates of the facility's potential to emit, as well as the likely performance of emission control technologies. LDEQ is confident that its evaluation is properly grounded in an understanding of the relevant performance of the process equipment and control devices, all of which LDEQ has current or prior regulatory experience. Finally, EPA guidance is clear that where two control technologies have substantially similar control effectiveness, the most cost effective technology may be selected. In this case, the two acid gas treatment processes achieve substantially similar results. It is therefore reasonable and appropriate to leave the final choice between vendors to the permit applicant.

Comment No. VII.4

Permit No. PSD-LA-751 must be clarified and reissued for public review and comment because it is impossible to identify exactly what LDEQ has determined to be BACT for DRI sources. A BACT determination consists of three parts: (1) the emission limitation; (2) the control technology that the limitation is based on; and (3) the compliance provisions. None of these parts is found in the same place in the DRI Permits, creating significant ambiguity. The Specific Conditions do not specify the BACT control technologies or monitoring, recordkeeping or reporting to demonstrate continuous emission reductions, it key ingredient of a BACT determination. *See, e.g., 42 U.S.C. § 7410(j).* The Specific Conditions identify emission limitations that may represent BACT for some -- but not all - sources, but these emission limitations are not identical to the emission limitations included in the Criteria Pollutants inventory in the DRI Part 70 permit (some are presented in different units and others have a different numeric value). The Specific Requirements in the DRI Part 70 permit include monitoring, recordkeeping and reporting requirements for some sources, but these are not linked to BACT. While the two permits cross reference each other in an attempt to supplement the missing pieces in each, this scattered approach falls far short of satisfying either PSD or Part 70.

The public must be given an opportunity to provide informed participation in the PSD decision making process. 42 U.S.C. § 7470(5). Given the ambiguity and inconsistency in the DRI permits, the public cannot tell what, if any, control technologies Nucor must install, what emission rates represent BACT, or how Nucor will assure continuous emission reductions under PSD. In order to comply with PSD, BACT control technologies, emission limitations and monitoring requirements must be clearly stated in the Specific Conditions, and the DRI PSD permit re-issued for public review and comment.

LDEQ Response to Comment No. VII.4

All PSD requirements must be incorporated into the Title V permit. BACT selection was listed clearly in a table in Page 3 and 4 of the PSD permit. This table is included in Specific Condition No. 2 of the PSD permit.

The commenter identifies no specific condition or BACT determination that fails to include the three elements cited above. LDEQ's BACT determinations are set forth in the Preliminary Setermination Summary. Translation of these determinations into permit conditions is accomplished in the Part 70 permit. The Specific Requirements in the Part 70 permit are worded to ensure practical enforceability of the final conditions.

Comment No. VII.5

Steps 3 through 5 of the DRI BACT analyses are flawed. BACT is an emission limitation based on the maximum degree of reduction that is achievable. The BACT emission limit is selected by ranking the control technologies found to be feasible in Step 2 by control effectiveness, which must include:

- control effectiveness (percent pollutant removed);
- expected emission rate (tons per year and pounds per hour);
- expected emission reduction (tons per year);
- energy impacts;
- environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
- economic impacts (total cost effectiveness, incremental cost effectiveness)

In Step 4, the top control is selected unless adverse energy, environmental, and economic impacts are documented. One moves down the list until a control is found that has no adverse impacts. In Step 5, the top-ranked control option with no adverse impacts is selected as BACT. As the Step 3 ranking is based on control effectiveness and emission rate, the selected BACT control technology is accompanied by a corresponding emission rate and control efficiency, which become permit conditions. The Nucor and LDEQ BACT analyses selected top-ranked control technologies, but did not determine an emission rate based on the maximum degree of reduction that is achievable, the lynchpin of the BACT definition. Instead, emissions are calculated elsewhere and assumed with no support to represent BACT.

The majority of the BACT analyses in the DRI Application and LDEQ's determination stopped at identifying the top control technology. None of the BACT determinations specify the emission rate or expected emission reduction. Some identify the control effectiveness in the Step 3 ranking, but none of them identify the uncontrolled emissions so it is impossible to determine the corresponding BACT emission limitation. The leap from control technology to emission rate is undocumented in the record. Instead, the BACT emission limitation and degree of emission reduction are determined outside of the top-down BACT analysis, in the emission calculations of the DRI Application. The BACT emission limitation and degree of emission reduction appear in the draft permits with no bridge between the control technology determination and the emission limitation. The BACT emission limitation itself should be selected in the top-down BACT analysis.

LDEQ Response to Comment No. VII.5

Nucor selected the top ranked technologies that are technologically and economically feasible. Analysis of other lower efficiency technologies is therefore not necessary or required. Permitted emission rates are derived from the selected technologies.

The comment lacks specificity for the sources to which it purports that BACT has been improperly applied. The applicant provided emission calculations on the basis of the control technologies

presented as BACT, and these control technologies were deemed to be BACT by LDEQ. The emission calculations have been incorporated into the Title V permit as emission rate limitations. In the case of operational or work practice standards being determined as BACT, a parametric compliance demonstration may be appropriate, or compliance with the work practice standard itself may be deemed to be compliance with BACT.

Comment No. VII.6

The DRI Permits violate PSD and Part 70 because control technologies are not specified in the permits. As noted above, all of the BACT analyses concluded that BACT is a specific control technology for a respective pollutant. Emission calculations presumably assume this control technology is used to achieve the emission rates in the "Emission Rates for Criteria Pollutants" table in the draft DRI Part 70 Permit and that were modeled to determine compliance with ambient air quality standards.

However, these control technologies, with very few exceptions, were not required in either the PSD Specific Conditions or in the Part 70 Specific Requirements. The technology upon which BACT emission limits are based should be specified in the permit. See NSR Manual, p. B.56. The indicator monitoring requirements, on scrubbers and baghouses, for example, do not make any sense unless a control technology is specified as BACT. If BACT were determined to be a scrubber and monitoring were specified as the flow rate and pressure drop across the scrubber, these conditions would be mute if a baghouse were installed.

Further, alternate technologies, for example, may impact other regulated pollutants, especially those that are below PSD significance thresholds. For example, if a baghouse were selected as BACT for PM₁₀, it would reduce much more lead and sulfuric acid mist than other particulate controls. If a scrubber or an electrostatic precipitator were installed instead, lead and sulfur acid mist emissions would be higher, perhaps triggering PSD review. This result would not be detected as these pollutants would not otherwise be monitored. Similarly, low-NO_x burners, while reducing NO_x, can increase CO and VOC emissions.

To assure continuous emission reductions and to provide the public the required opportunity for informed participation in the decision making process, the DRI Permits should be withdrawn and re-issued for public review and comment after BACT is clearly specified.

LDEQ Response to Comment No. VII.6

BACT selection was listed clearly in a table in Page 3 and 4 of the PSD permit. This table is included in Specific Condition No. 2 of the PSD permit.

The PSD permit establishes emission limitations for each source subject to PSD review, and each control technology evaluated for each source during the BACT review is discussed in the body of the permit. There are no cases in which a high-energy wet scrubber was selected as BACT in which a baghouse was determined to be technically feasible. DRI products require special handling in order to limit the possibility of fires, for which several dry dust removal technologies such as baghouses are not appropriate. The monitoring parameters indicated in the Title V permit are appropriate for the control technology applied to the source to which they are associated, and the conditions for these sources make clear which technology is applied.

Comment No. VII.7

Permit No. PSD-LA-751 must -- but does not -- create practicably enforceable conditions to assure continuous emission reductions and that the selected BACT emission limitations will be met. A PSD permit must be a stand-alone document that “establishes emissions standards or other operational limits to be met; specifies methods for determining compliance and/or excess emissions, including reporting and recordkeeping requirements; and outlines the procedures necessary to maintain continuous compliance with the emission limits.” *See* NSR Manual, p. H.1. When a PSD permit “requires add-on controls operated at a specified efficiency level [i.e., BACT], permit writers should include, so that the operating efficiency condition is enforceable as a practical matter, those operating parameters and assumptions which the permitting agency depended upon to determine that the control equipment would have a given efficiency.” *See* Terrell E. Hunt, “Guidance on Limiting Potential to Emit in New Source Permitting,” June 13, 1989, p. 7. Continuous emissions monitoring should be specified in the PSD permit unless infeasible, in which case surrogate monitoring parameters, e.g. opacity or pressure drop, should be specified. *See* NSR Manual, p. H.6; Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and § 112 Rules and General Permits, Kathie A. Stein, Jan. 25, 1995, pp. 8-9; Operating and maintenance procedures for monitoring equipment should also be specified. *See* NSR Manual, p. H.7.

For almost every emission source, the Preliminary Determination Summary in the DRI PSD permit identified a control technology with specific control efficiency. To assure continuous emission reductions and practicable enforceability of each BACT determination, the DRI PSD permit should also have included specific conditions requiring continuous monitoring of emissions and the operating parameters -- and specific design assumptions -- that LDEQ relied upon in making the BACT determination. As described more fully in the comments that follow, the DRI PSD permit does not include any monitoring requirements or design parameters necessary to assure compliance with BACT. Instead, Specific Condition #8 purports to incorporate such conditions by reference, and provides that: “All emission limitations, monitoring, recordkeeping, and reporting requirements of Permit No. 2560-00281-V0 related to TSP/PM10/PM2.5/SO2/NOx/CO and VOC emissions are also terms and conditions of this PSD permit.”

This attempt to incorporate Part 70 permit conditions into the PSD permit falls short, for several reasons. First, Permit No. 2560-00281-V0 is the initial pig iron Part 70 permit, not the DRI Part 70 permit. Although some of the pig iron sources were “transferred” from the pig iron Part 70 permit to the DRI Part 70 permit, none of those sources is addressed in the DRI PSD permit -- even though, as described more fully below, each transferred source requires a new BACT determination and should have been included in the air quality impact analysis for the DRI process. In other words, Specific Condition #8 is an empty shell and does not actually transfer anything relevant to the DRI PSD permit as published for public comment.

Even if were not empty, Specific Condition #8 puts the cart before the horse. “The distinction between preconstruction and operating permits is critical.” *United States v. Marine Shale Processors*, 81 F.3d 1329, 1355 (5th Cir. 1996). At the preconstruction, i.e., PSD, stage, “the permitting authority must determine whether the proposed construction or modification would violate [the] state's emissions control strategy or interfere with attainment or maintenance of CAA air quality standards.” *Id.* Thus, the PSD permit that results from the agency's preconstruction review is the legal mechanism through which PSD requirements become applicable, and remain applicable, to an individual source. *See* John S.

Seitz to Robert Hodanbasi et al., May 20, 1999, Enclosure A, p. 4. The emission limitations and other specific conditions in the PSD permit are “applicable requirements” that must be incorporated into the source’s Part 70 permit. In other words, operating and monitoring conditions, together with BACT emission limitations, must be established in the PSD permit and these are to be incorporated specifically (not by reference) into the source’s Part 70 permit. This process does not work in reverse -- limitations and other conditions in an *operating* permit cannot be incorporated into a *preconstruction* permit -- specifically or by reference.

LDEQ Response to Comment No. VII.7

According to the signature page of Permit No. 3086-V0, the permit is “both a state preconstruction and Part 70 Operating Permit.” Procedurally, LDEQ issues PSD and Part 70 (Title V) permits concurrently as a matter of course. As per 40 CFR 70.6(c)(1), Part 70 permits must contain “testing, monitoring, reporting, and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit,” and the BACT limitations established by the PSD have been incorporated into the Title V.

LDEQ notes that the NSR Manual predates EPA’s Part 70 Operating Permits Program, even the Clean Air Act Amendments of 1990, the statutory basis of the Title V program. Thus, it is easy to understand why this document suggests that practically enforceable conditions should be included in a PSD permit to ensure the BACT limitations are met – Title V permits, which must include “emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance” per 40 CFR 70.6(a)(1), did not exist. Given today’s regulatory framework and the fact that LDEQ requires an applicant to secure a Part 70 permit before construction commences, it is simply improper to review a PSD permit in isolation.

The reference to Permit No. 2560-00281-V0 in Specific Condition 8 of proposed PSD-LA-751 is a typographical error. This condition should read, “All emission limitations, monitoring, recordkeeping, and reporting requirements of Permit No. 3086-V0 related to TSP/PM₁₀/PM_{2.5}, SO₂, NO_x, CO, VOC, and CO₂e emissions are also terms and conditions of this PSD permit.” LDEQ believes such a requirement is preferable, from an administrative perspective, to establishing numerous conditions in PSD-LA-751 identical to those set forth in Permit No. 3086-V0.

The commenter states that PSD permits may not incorporate any condition of a Title V permit. The Clean Air Act does not require such a distinction. LDEQ has historically issued PSD and Part 70 permits in tandem, making the required PSD determinations in the PSD permit and translating those determinations into permit language in the Part 70 permit. By so doing, LDEQ has provided public notice opportunities for challenge *beyond* what is required by the PSD program. With respect to the commenter’s assertion that PSD and Part 70 may not be combined, LDEQ notes that EPA has approved, as fully meeting both PSD and Title V requirements, unitary permit programs that make no distinction between preconstruction and operating permit requirements. The commenter’s assertion that LDEQ’s long standing permitting practice is inconsistent with the Clean Air Act is without merit.

The PSD permit does establish emission limitations based upon the BACT review of each source. The Title V operating permit acts as the enforcement tool for PSD conditions, and requirements for specific monitoring actions and compliance demonstrations, such as operating parameters and performance tests, are contained within that document. These conditions are clearly “enforceable as a practical manner.”

Comment No. VII.8

The BACT determinations fail to separately analyze and set limits specific to PM₁₀ and PM_{2.5}. Nucor's BACT analyses include a separate top-down BACT analysis for PM₁₀ and PM_{2.5}. However, LDEQ combined the two analyses and failed to set separate BACT emission limitations for PM₁₀ and PM_{2.5} in either the PSD permit or part 70 permit for the DRI process. BACT must be selected "for each pollutant subject to regulation." 42 U.S.C. § 7475(a)(4). BACT is an emission limitation "based on the maximum degree of reduction for each pollutant subject to regulation under [PSD] that would be emitted from [the source]." 42 U.S.C. § 7479(3); LAC 33:III.509.A. PM₁₀ and PM_{2.5} are *not* the same pollutant and are subject to different NAAQS standards. Moreover, a given control different control technologies may (and generally will) provide a different degree of reduction for PM₁₀ than for PM_{2.5}, and a technology that is BACT for PM₁₀ emissions from a source might not be BACT for PM_{2.5} emissions from the same source. Nucor should be required to submit separate BACT analyses for PM₁₀ and PM_{2.5} emissions from each DRI source.

LDEQ Response to Comment No. VII.8

Nucor provided a top-down BACT analysis for PM_{2.5} and the requisite modeling analyses to demonstrate that the facility's emissions will not result in violations of the annual and 24-hour PM_{2.5} NAAQS. A combined PM₁₀/PM_{2.5} analysis is sufficient where it demonstrates that both pollutants are being controlled to BACT levels. The commenter has presented no evidence showing that this demonstration is inadequate.

LDEQ has included PM_{2.5} limitations in the final permits.

Comment No. VII.9

The BACT determination for Iron Oxide Storage and Handling (DRI-101/201, DRI-102/202, DRI-102/202) is flawed and should be revised. Iron oxide storage and handling includes transfer to conveyors and conveying (DRI-105/205), screening (DRI-102/202), and storage in day bins (DRI-101/201). The BACT analysis concluded that BACT for PM₁₀/PM_{2.5} is a baghouse achieving at least 99.5% control for PM₁₀/PM_{2.5} with enhanced filtration media for PM_{2.5} and hooded conveyors and enclosed transfer stations for material handling. The BACT analysis did not establish any emission limits for these control technologies. There are several problems with this determination.

First, the selected BACT control, a fabric filter baghouse, is routinely designed to remove 99.9% to 99.99% of the particulate matter. The proposed BACT control level of 99.5% is unsupported and quite low for the subject source. And selecting a baghouse alone does not go far enough. Baghouse performance depends upon the type of bags (e.g., fiberglass, Ryton, P-84), the number of bags per module, and the cleaning method that is employed (e.g., pulse jet, reverse air, shaker). *See, e.g.,* Kenneth E. Noll, Fundamentals of Air Quality Systems. Design of Air Pollution Control Devices, American Academy of Environmental Engineers; Scientific Dust Collectors, A Scientific Review of Dust Collection; R.P. Donovan, Fabric Filtration for Combustion Sources. Fundamentals and Basic Technology, Marcel Dekker, 1985; John D. McKenna, James H. Turner, and James P. McKenna Jr., Fine Particle (2.5 microns) Emissions, John Wiley & Sons, 2008. The BACT analysis and DRI PSD permit do not provide any of this information for the proposed baghouse, precluding any meaningful commentary.

Second, a separate BACT determination was not provided for each emission generating source, which are controlled by different devices or work practices. Rather, a single determination was performed which focused on control of emissions from point sources, the day bins and screening operations vented through the baghouse. No separate BACT analysis was performed for the material handling operations. Instead, the BACT controls for material handling were stated in Step 5 of the BACT analysis without going through Steps 1 through 4. As a result, more effective controls for material handling were not considered, including, for example, the Dust Control Plan, complete enclosure of iron oxide storage and handling operations, fully enclosed conveyors, and combinations of control technologies.

Third, BACT is an emission limit based on the maximum degree of reduction that is achievable. A control technology alone, as specified for $PM_{10}/PM_{2.5}$, satisfies BACT only if there are technical impediments to the measurement of emissions. This is not the case here as the draft permits set a specific concentration limit of 0.002 grains per dry standard cubic foot (“gr/dscf”) on PM_{10} emissions from the day bins, screening operations, and the furnace feed conveyor baghouse.

Fourth, there is no link between the identified control technology, the control efficiency (99.5%), the BACT concentration limit of 0.002 gr/dscf, and the rates in lb/hr and ton/yr. The uncontrolled PM_{10} and $PM_{2.5}$ emissions from each source should have been specified as the starting point for the BACT analysis. Absent this, there is no basis for concluding that 0.002 gr/dscf in fact corresponds to a 99.5% reduction in $PM_{10}/PM_{2.5}$ from the subject sources. The emission calculations start with a “cleaned gas dust loading” (*i.e.*, already controlled) of 4.08 milligrams per cubic meter at standard conditions (“mg/Nm³”) for DRI-105/205 and 4.17 mg/Nm³ for DRI-102/202 and a (controlled/uncontrolled?) “gas dust loading” of 4.12 mg/Nm³ for DRI-101/201, without any explanation of how these levels were picked (they should have been selected in the BACT analysis) or relate to the required control technology and control efficiency. These gas dust loadings correspond to 0.002 gr/dscf, the BACT emission limitation, which is thus unsupported in the record.

Fifth, the DRI PSD permit -- and consequently the DRI Part 70 permit -- does not require that Nucor actually install the control technology concluded to be BACT, but rather, only places limits on operation in the form of concentrations and emission rates, that have no computation or engineering link to the technology itself. When there is no technical impediment to measuring emissions, as is the case here, the PSD permit should include specific conditions specifying both the BACT emission limit and the control technology that must be employed continuously to achieve that limit. The DRI Permits should be modified to require the installation of bag houses equipped with enhanced filtration media capable of removing 99.5% of the emitted PM_{10} and $PM_{2.5}$ as well as hooded conveyors and enclosed transfer stations for material handling.

Sixth, the DRI PSD permit does not establish any BACT limit for $PM_{2.5}$. The DRI Part 70 permit includes limits for “cleaned gas dust loadings” of 4.08, 4.12, and 4.17 mg/Nm³, but these limits correspond to total suspended particulate matter (“TSP”). Nucor’s emission calculations indicate that only 75% of TSP is $PM_{2.5}$. Thus, the DRI PSD permit should include a separate BACT determination for $PM_{2.5}$, and if the determination is that the same control technology and level of control applies to PM_{10} and $PM_{2.5}$, the PSD permit -- and consequently, the Part 70 permit -- should be revised to include a $PM_{2.5}$ BACT emission limit of 0.00135 gr/dscf (calculated as $(0.75)(4.12 \text{ mg/Nm}^3)(0.0283 \text{ Nm}^3/\text{ft}^3)/(64.79891 \text{ mg/gr}) = 0.00135 \text{ gr/dscf}$), and monitoring, recordkeeping, and

reporting requirements.

LDEQ Response to Comment No. VII.9

Emission limits for DRI-101/201, DRI-102/202, and DRI-105/205 are set forth in both the Part 70 and PSD permits (Specific Condition 6 of the PSD-LA-751).

The fabric filter baghouse will achieve a minimum of 99.5 percent efficiency based on the design particulate loading and gas flow rate. An emissions guarantee of 0.002 grains of particulate (PM₁₀) per standard cubic feet (gr/scf) of gas was made by the manufacturer. This limit is listed in Specific Condition 2 of the PSD permit and in the Specific Requirements of the Title V permit. The commenter alleges that fabric filters are “routinely designed to remove 99.9% to 99.99% of the particulate matter.” However, the commenter fails to indicate for which particle size distribution he believes this applies. Baghouse control efficiency is known to increase with increasing particle size, and vice versa. LDEQ has required a minimum control efficiency of 99.5% of particles with an aerodynamic diameter of 2.5 microns or less, the smallest particle size group currently regulated. Greater efficiencies at larger particle size distributions are assured by this requirement.

Regarding the allegation that the permits do not require Nucor to actually install the control technology determined as BACT, LDEQ’s BACT determinations are set forth in the table on pages 3 and 4 of the PSD permit. This table is also included as Specific Condition 2 of the PSD permit.

Material handling and iron oxide storage pile sources addressed BACT and underwent review as part of the issuance PSD-LA-740. These infrastructure sources were transferred to the DRI permits. These sources were also included in the air quality impact analysis submitted by Nucor for PM₁₀ and PM_{2.5}. An alteration of the BACT determination was not deemed necessary, as their basic design has not been changed. LDEQ considers the NSLA Dust Management Plan to be a requirement of all such sources at the site and represents a suite of controls that represent BACT for sources of fugitive dust such as storage piles and material handling conveyors. This plan has been attached to and made part of PSD-LA-751 (see Specific Condition 8).

LDEQ has included PM_{2.5} limitations in the final permits.

Comment No. VII.10

The BACT determination for the Iron Oxide Coating Bin (DRI-103/203) is flawed and should be revised. Iron oxide pellets are coated with limestone prior to transfer to the furnace. The pulverized limestone is received by truck and pneumatically conveyed to a limestone storage bin. The pellets are then mixed with limestone and water in the iron oxide coating bin (DRI-103/203). The BACT analysis concluded that BACT for PM₁₀/PM_{2.5} is a baghouse achieving at least 99.5% control for PM₁₀/PM_{2.5} with enhanced filtration media for PM_{2.5}. The BACT analysis did not establish any emission limits for these control technologies. There are several problems with this determination.

First, it is not clear whether the limestone storage bin is a separate emission point, or whether it vents through the coating bin filter. This should be clarified. If it is a separate emission point, a BACT analysis should be prepared.

Second, BACT is an emission limit based on the maximum degree of reduction that is achievable. A control technology alone, as specified for PM₁₀/PM_{2.5} satisfies BACT only

if there are technical impediments to the measurement of emissions. This is not the case here as the draft permits set a specific concentration limit (0.02 gr/dscf) on PM10 emissions from the coating bins (DRI-103/203, Specific Requirements #50 and #198). However, the record contains no evidence that the emission limit of 0.02 gr/dscf, which was selected outside of the BACT analysis and is unsupported, represents the maximum degree of reduction that is achievable with the best available control technology.

Third, there is no link between the identified control technology, the control efficiency (99.5%), the emission limit of 0.02 gr/dscf, and the BACT PM10 emission limits in lb/hr and ton/yr. The uncontrolled PM10 and PM2.5 emissions from each source should have been specified as the starting point for the BACT analysis. Absent this, there is no basis for concluding that 0.02 gr/dscf corresponds to a 99.5% reduction in PM10/PM2.5 from the subject sources. The emission calculations start with a “gas dust loading” of 40.03 mg/Nm³ without any explanation of how this level was picked (it should have been selected in the BACT analysis) or relate to the required control technology and control efficiency. This gas dust loading corresponds to 0.0175 gr/dscf, the level established as BACT.

Fourth, the DRI PSD permit -- and consequently the DRI Part 70 permit -- does not require Nucor to install the control technology concluded to be BACT, but rather, only places limits on operation in the form of concentrations and emission rates that have no computation or engineering link to the technology itself. When there is no technical impediment to measuring emissions, as is the case here, the PSD permit should include specific conditions specifying both the BACT emission limit and the control technology that must be employed continuously to achieve that limit. The DRI Permits should be modified to require the installation of baghouses equipped with enhanced filtration media capable of removing 99.5% of the PM10 and PM2.5.

Fifth, the DRI PSD permit does not establish any BACT limit for PM2.5. The DRI Part 70 permit includes a limit for “cleaned gas dust loadings” of 40 mg/Nm³, but this limit corresponds to TSP. The emission calculations indicate that only 75% is PM2.5. Thus, the DRI PSD permit -- and consequently the DRI Part 70 permit -- should be revised to include a BACT concentration limit of 0.0131 gr/dscf for PM2.5 (calculated as $(0.75)(40 \text{ mg/Nm}^3)(0.0283)/(64.79891 \text{ mg/gr}) = 0.0131 \text{ gr/dscf}$).

LDEQ Response to Comment No. VII.10

Emission limits for DRI-103/203 are set forth in both the Part 70 and PSD permits (Specific Condition 6 of the PSD-LA-751).

Regarding the allegation that the permits do not require Nucor to actually install the control technology determined as BACT, LDEQ’s BACT determinations are set forth in the table on pages 3 and 4 of the PSD permit. This table is also included as Specific Condition 2 of the PSD permit.

“Limestone storage bin” and “coating bin” have been used interchangeably, since as the commenter notes, the coating is composed of crushed limestone. In any event, only one emission point of this type is permitted within each DRI plant. The limestone storage bin is a vessel which vents through the named emission point “Coating Bin Filter.”

As stated in the PSD permit and explained in LDEQ Response to Comment No. 9, the BACT limit of 99.5% control efficiency applies equally to PM_{2.5} as it does to PM₁₀ and TSP. This limit makes

PM_{2.5} the driver for compliance, ensuring higher control efficiencies for larger particle size distributions.

LDEQ has included PM_{2.5} limitations in the final permits.

Comment No. VII.11

The BACT determination for the Iron Oxide Fines Storage and Handling (DRI- 104/204) is flawed and should be revised. The screening and handling of iron oxide pellets generates undersized material referred to as fines. This material is stored in an outdoor pile until transferred as feed material to the sinter plant, the on-site briquetting plant, or sold to outside buyers. The fines are transferred by truck and front end loader, which generate fugitive PM₁₀/PM_{2.5} emissions.

The Preliminary Determination Summary concludes that BACT for PM₁₀ and PM_{2.5} for iron oxide fines storage and handling is: (1) application of a chemical surface stabilizer on the iron oxide storage piles (95% control efficiency); (2) use of water sprays locally to control dust from stacking, reclaiming, and pile maintenance (90% control efficiency); and (3) minimizing handling (50% control efficiency). However, Specific Condition #3 in the DRI PSD permit -- and Specific Requirements #52 and #199 in the DRI Part 70 permit -- specifies that BACT for PM₁₀ is only “implementation of wet suppression of dust generating sources by water sprays at each storage pile.” Thus, the DRI PSD permit -- and consequently the DRI Part 70 permit -- fails to require BACT. The Specific Conditions -- and Specific Requirements -- must be modified to include *all* components of BACT for this source.

In addition, the PSD permit does not require any testing or recordkeeping to assure that BACT is met and that the selected control technology provides continuous emission reductions. The emission calculations are based on many assumptions including throughputs, silt contents, dozer miles per day, pile maintenance hours, etc. There is no monitoring or recordkeeping for any of these assumptions. How frequently must water sprays be used to assure the control efficiencies assumed in the emission calculations? How much water must be applied each time and under what conditions? What must be done to assure chemical application reduces wind erosion by 95%? Where is the recordkeeping for the number and types of trucks and heavy equipment assumed in the emission calculations? LDEQ should require testing of this source or, at a minimum, explain why no testing of DRI-104/204 is required.

In addition, as described in previous comments, the DRI PSD permit must -- but does not -- establish a separate BACT limit for PM_{2.5}.

LDEQ Response to Comment No. VII.11

LDEQ agrees that BACT was determined to be the application of surface stabilizers to the source and minimized handling, and concedes that these aspects of the BACT determination were not clearly translated into the proposed Title V permit. The language of the Title V Specific Requirements has been amended to include the application of chemical stabilizers after each disturbance of the pile and to require that “minimized handling” be taken to mean the pile should only be disturbed for the purpose of adding or removing material.

In this instance, direct measurement of emissions is not technically feasible. According to the definition of “Best Available Control Technology (BACT),” if “the administrative authority

determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of *best available control technology*.¹³¹

The NSR Manual restates this aspect of the definition as follows:

In addition, if the reviewing authority determines that there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant to the maximum extent.¹³²

A condition requiring Nucor to comply with the NSLA Dust Management Plan is included in both the Title V and PSD permits.

LDEQ has included PM_{2.5} limitations in the final permits.

Comment No. VII.12

The BACT determination for Product Fines Briquetting (DRI-117) is flawed and should be revised. The screening and handling of DRI results in undersized material or fines. These fines are mixed with a cement binder and pressed in molds to form bricks for use in blast furnaces.

The Preliminary Determination Summary concludes that BACT for PM₁₀ and PM_{2.5} for the briquetting mill is a high-energy wet scrubber achieving at least 99% control of PM₁₀ and PM_{2.5}, and installation of hooded conveyors and enclosed transfer stations to limit emissions from material handling. However, Specific Condition #2 in the DRI PSD permit - - and Specific Requirement #145 in the DRI Part 70 permit -- sets a concentration limit on PM₁₀ of 0.0022 gr/dscf, but does not require the specific controls specified as BACT. There are several problems with this determination.

First, apparently, there are three separate emission generating processes in the briquetting area: (1) the mill; (2) material handling, and (3) storage silos. The BACT determination discusses only the mill. BACT for material handling and storage silos is stated in Step 5 with no supporting analysis.

Second, BACT is an emission limit based on the maximum degree of reduction that is achievable. Specification of a control technology alone satisfies BACT only if there are technical impediments to the measurement of emissions. This is not the case here as the Specific Conditions set a specific concentration limit (0.0022 gr/dscf) on PM₁₀ emissions from the briquetting mill. However, the record contains no evidence that this concentration limit, which was selected outside of the BACT analysis and is unsupported, represents the maximum degree of reduction that is achievable with the selected control technology.

Third, the draft permit sets a single BACT particulate matter concentration limit of less than

¹³¹ LAC 33:III.509.B

¹³² NSR Manual, pg. B.2

or equal to 0.0022 gr/dscf, which is labeled PM₁₀. However, the emission calculations indicate that this is not PM₁₀, but rather total suspended particulate matter or TSP. Of this total, 99% is PM₁₀ and 90% is PM_{2.5}. The regulated PSD pollutants are PM₁₀ and PM_{2.5}. Thus, the draft permit must be modified to set specific limits on PM₁₀ and PM_{2.5}, rather than on TSP.

Fourth, there is no link between the identified control technology and the specified PM₁₀ concentration limit. The uncontrolled PM₁₀ and PM_{2.5} emissions should have been specified as the starting point for the BACT analysis. There is no basis for concluding that 99% control is achieved unless the uncontrolled level is disclosed and supported. The emission calculations start with a cleaned gas dust loading of 5 mg/Nm³ without any explanation of how that level relates to the required control technology.

Last, the DRI PSD permit -- and consequently the DRI Part 70 permit -- does not require Nucor to install the control technology concluded to be BACT, but rather only places limits on operation in the form of concentrations and emission rates that have no computation or engineering link to the technology itself. When there is no technical impediment to measuring emissions, as is the case here, the PSD permit should include specific conditions specifying both the BACT emission limit and the control technology that must be employed continuously to achieve that limit. The DRI Permits should be modified to require the installation of hooded conveyors and enclosed transfer stations, and a high-energy wet scrubber capable of achieving at least 99% control of PM₁₀ and PM_{2.5}.

LDEQ Response to Comment No. VII.12

At the design particulates loading and gas flow rate, the proposed scrubber achieves a minimum efficiency of 99 percent. At this level, a guarantee of 0.0022 grains of particulates per standard cubic foot (gr/scf) of gas was made by the manufacturer.

Emission limits for PM₁₀ and PM_{2.5} from DRI-117 are set forth in both the Part 70 and PSD permits (Specific Condition 6 of the PSD-LA-751).

The commenter states that Specific Condition 2 of the proposed DRI PSD permit and Specific Condition 145 of the Part 70 permit fail to fully capture the BACT determination, which in addition to the numeric limit, should include hooded conveyors and enclosed transfer stations. LDEQ agrees that BACT was determined to include hooded conveyors and enclosed transfer stations at the source and concedes that these aspects of the BACT determination were not clearly translated to the Title V permit. For clarity, LDEQ has included a facility-wide requirement to install hooded conveyors and enclosed transfer stations at the DRI facility as BACT.

The commenter argues that the 0.0022 gr/dscf lacks foundation. This is in error. The 0.0022 gr/dscf constitutes application of the selected BACT technology (high energy wet scrubber) to the specific situation to determine the numeric standard. An adequate basis thus exists for the conclusion that the 0.0022 gr/dscf represents BACT. The commenter has presented no evidence that this does not represent BACT.

Regarding the allegation that the permits do not require Nucor to actually install the control technology determined as BACT, LDEQ's BACT determinations are set forth in the table on pages 3 and 4 of the PSD permit. This table is also included as Specific Condition 2 of the PSD permit.

Comment No. VII.13

The BACT determination for Product Loading (DRI-118) is flawed and should be revised. DRI pellets will be conveyed from storage silos (DRI-111/112) and loaded onto barges at the dock for shipment to other Nucor facilities. The top-down analysis concluded that BACT for PM10 and PM2.5 for DRI loading is a high-energy wet scrubber achieving at least 99% control of PM10 and PM2.5, and installation of hooded conveyors and enclosed transfer stations to limit emissions from material handling and a scrubber will be installed on the product storage silos for dust control. There are a number of problems with this BACT determination.

First, the Specific Conditions section of the DRI PSD permit indicates that Specific Condition #3 applies to Product Loading (DRI-118). This condition requires wet suppression of dust generating sources by water sprays at each storage pile. Specific condition clearly does not apply to DRI-118. The DRI PSD permit must be revised to include specific condition(s) applicable to this source.

If, in fact, Specific Condition #5 was intended to apply to DRI -118, this specific condition -- and consequently Specific Requirement #154 in the DRI Part 70 permit -- does not incorporate the BACT determination for this source. Specific Condition requires a high energy scrubber with only a 90% control efficiency, whereas the BACT determination for this source is that the scrubber achieve at least 99% control.

Third, BACT for conveyors and transfer stations was stated in Step 5 with no supporting top-down analysis. Unless the conveyors and transfer stations are completely enclosed and vent to the Product Loading Scrubber (and the permit record is ambiguous on this point), a BACT analysis should have been conducted for conveying and transfer stations and additional controls considered, such as fully enclosed conveyors and transfer stations and a full enclosure of the loading area.

Fourth, the Specific Conditions in the DRI PSD permit -- and consequently the Specific requirements in the Part 70 permit -- do not require Nucor actually to use hooded conveyors and enclosed transfer stations, which also are selected as BACT in the Preliminary Determination Summary. All control technologies determined to constitute BACT must be specified in the Specific Conditions.

Fifth, BACT is an emission limit based on the maximum degree of reduction that is achievable. A control technology alone satisfies BACT only if there are technical impediments to the measurement of emissions. This is not the case here as a scrubber is a control device that emits exhaust gases that can be measured using standard U.S. EPA test methods. The DRI PSD permit -- and consequently the DRI Part 70 permit -- must, but does not, set BACT emission limits for product loading.

Finally, the DRI PSD permit must but does not contain separate BACT or other emission limits for PM2.5.

LDEQ Response to Comment No. VII.13

The commenter is correct that the proposed PSD permit indicates Specific Condition 3 in error; this entry should have read Specific Condition 5. This requirement, however, is Specific Condition 3 in the final PSD permit.

The commenter is correct that the wet scrubber selected as BACT must meet a control efficiency of

99% of the dust collected by the scrubber. However, because barge loading operations are necessarily a more open activity than conveyor transfer stations and the like, the specific condition takes into account the collection efficiency of dust generated by barge loading operations, and requires a combined control efficiency of not less than 90%.

LDEQ has included a facility-wide requirement to install hooded conveyors and enclosed transfer stations at the DRI facility as BACT.

Emission limits for DRI-118 are set forth in both the Part 70 and PSD permits (Specific Condition 6 of the PSD-LA-751).

LDEQ has included PM_{2.5} limitations in the final permits.

Comment No. VII. 14

The BACT determination for Cooling Towers (DRI-113/213, DRI 114/214) is flawed and should be revised. The facility will include four process cooling towers. The Preliminary Determination Summary concludes that BACT for PM10 and PM2.5 emissions from these towers is a combination of cooling water containing less than 1,000 mg/l total dissolved solids (“TDS”) and drift eliminators designed to achieve a maximum drift rate of 0.0005%. BACT, however, is an emission limitation based on the maximum degree of reduction that is achievable. The cooling tower BACT analysis failed to meet this test.

The DRI Application BACT analysis specified only a “low TDS” concentration in the circulating water. LDEQ's BACT determination concludes that “BACT is a combination of less than or equal to 1,000 milligrams per liter TDS concentration in the cooling water and drift eliminators employing a drift maximum of 0.0005%. The record contains no support for the 1,000 mg/L TDS concentration. Water supplies available to the facility can contain a wide range of TDS concentrations, depending upon water source and in-plant treatment. Does it represent the maximum degree of reduction in cooling tower emissions that is achievable? Are lower TDS waters available locally? Did Nucor consider treating its water supply to remove TDS? The records that we reviewed contain no support for the leap from “low TDS” to 1,000 mg/L. The record must demonstrate that 1,000 mg/L satisfies the maximum degree of reduction requirement in the definition of BACT by providing a study that identifies available water supplies, their quality, and assesses treatment and alternate supply options to obtain a lower TDS value.

In addition, BACT is defined as an emission limitation. The DRI PSD permit contains no BACT or other emission limits for either PM10 or PM2.5 from the cooling towers. A TDS concentration and drift rate combined do not limit PM10 or PM2.5 emissions from the cooling towers. A third parameter, the circulating water flow rate, also must be specified to limit emissions. The Specific Requirements in the DRI Part 70 permit seem to acknowledge this by noting that compliance is determined based on measured TDS, “the design cooling tower circulating water rate (as installed)” and “a percent drift of 0.0005%.” The DRI PSD permit, however, does not contain any limit on the circulating water rate itself, or any requirement to monitor and report it. The PSD permit -- and consequently the Part 70 permit -- should be revised to incorporate limits on cooling water circulation; otherwise, excessive recirculation could result in much higher emissions than are necessary or reflected by Nucor's ambient air quality analysis.

LDEQ Response to Comment No. VII.14

Direct measurement of emissions from cooling towers is not technically feasible. Particulate emissions result when the drift droplets evaporate and leave fine particulate matter formed by crystallization of dissolved solids. Therefore, BACT limitations such as those suggested by the commenter (e.g., exhaust gas concentration or % reduction) are not appropriate.

BACT is the use of towers with internal baffles and limiting the total dissolved solids (TDS) concentration in the cooling water to less than or equal to 1000 milligrams per liter. To ensure compliance with the permit limits, the following conditions are included in the Title V permit:

1. The design drift efficiency of 0.0005% and cooling tower circulating water rate shall be verified by vendor certification.
2. Maintain the assembled cooling tower drift eliminators consistent with the manufacturer's recommendation as described in the operating manual for the cooling tower. Compliance shall be documented by maintaining a log of maintenance activity performed on the cooling tower drift eliminators.
3. Within 180 days after initial startup or within 60 days after achieving the normal production rate, whichever is earliest, collect a grab sample of the cooling water at least once per day for seven consecutive operating days, analyze each sample in accordance with Standard Method 2540 C or EPA Method 160.1, and record the results. Subsequently, collect a grab sample of the cooling water at least once per week, analyze each sample using one of the aforementioned methods, and record the results. Alternate methods may be used with prior approval of the department. Compliance shall be determined based on the sampling results, the design cooling tower circulating water rate (as installed), and a percent drift of 0.0005%.

Use of the design cooling tower circulating water rate will result in conservative emission estimates and negates the need to monitor this parameter.

Nucor cannot increase PM₁₀ emissions from the cooling towers “without limit.” Average and maximum pound per hour and ton per year limits are set forth in the “Emission Rates for Criteria Pollutants” section of the Title V permit.

Comment No. VII.15

Permit No. PSD-LA-751 does not assure that BACT will be employed for the Package Boilers (DRI-109/209). The facility includes two package boilers to provide steam to each DRI unit. The steam is used primarily to heat the reboiler in the acid gas absorption system and for utility purposes. The boilers fired on natural gas.

The Preliminary Determination Summary contains separate top-down BACT analyses for each pollutant. These analyses all conclude that BACT is a technology: PM₁₀/PM_{2.5} - good combustion practices; NO_x - low NO_x burners and SCR; SO₂ - pipeline quality natural gas; and CO and VOCs - good combustion practices.

The definition of BACT is an emission limitation based on the maximum degree of reduction. The BACT determinations do not establish an emission limitation for any of these pollutants. Rather, emission rates are calculated separately from the top-down BACT analyses, based on certain unsupported assumptions, some of which appear as draft permit conditions, but most of which do not. There is no thread to link: the technology-based BACT determination with the emission rates and operating limits in the permit conditions, which are plucked out of thin air. The permit record makes no attempt

to demonstrate that the subject emissions and operating limits represent the maximum degree of reduction that is achievable. Thus, the BACT analyses for all of these pollutants are fundamentally flawed.

LDEQ Response to Comment No. VII. 15

Emission limits for DRI-109/209 are set forth in both the Part 70 and PSD permits (Specific Condition 6 of the PSD-LA-751). Moreover, the assertion that the “emission rates and operating limits” were “plucked out of thin air” is simply inflammatory rhetoric. Nucor’s permit application includes the emissions calculations, the origin or basis for the calculations, and all assumptions and/or variables which serve as inputs necessary to calculate potential emissions.

Comment No. VII.16

The BACT determination for NOx emissions from DRI-109/209 is flawed and should be revised. The Preliminary Determination summary concludes that BACT for NOx emissions from the package boilers is the installation of low NOx burners combined with SCR.²⁴ The draft permits establish a NOx BACT limit of 0.00324 lb/MMBtu. We support the use of SCR and low NOx burners to control NOx from the package boilers. However, there are several problems with the translation of these controls in the DRI Permits.

First, although the DRI Part 70 permit includes a specific requirement to install SCR on the package boilers, the Specific Conditions in the DRI PSD permit do not. This violates 42 U.S.C. § 7475(a), pursuant to which the PSD permit must assure that the source will employ BACT. And when there is no technical impediment to measuring emissions, as is the case here, the PSD permit must include specific conditions specifying both the BACT emission limit and the control technology that must be employed continuously to achieve that limit.

Second, as explained in comment no. 14 above, there is no thread connecting the technology determinations with the BACT emission limits. The specified emission rates appear separate from the BACT determination. It is unclear, for example, whether these emission rates correspond to a 90% NOx reduction relative to uncontrolled emissions, or 90% reduction of NOx relative to the low-NOx burners. Generally, low-NOx burners can remove at least 50%+ of the NOx and an SCR can remove 90%+ of the remaining NOx for an overall NOx reduction of greater than 95%. Thus, it is unclear whether the proffered limits on NOx emission rates corresponds to the maximum degree of reduction that is achievable for low NOx burners and SCR combined. The maximum degree of reduction for low NOx burners and SCR combined is at least 95% relative to uncontrolled levels, not the 90% for the SCR only as specified in the DRI Part 70 permit condition. The DRI Application should have disclosed uncontrolled NOx emissions and the design low NOx burner and SCR control efficiencies, and should have included sufficient technical documentation to support these emissions and control efficiencies.

Finally, a BACT determination must be enforceable as a practical matter and must assure continuous emission reductions. The PSD permit must include appropriate monitoring and recordkeeping requirements to assure that BACT emission limits and conditions are met on a continual basis at all levels of operation. NSR Manual, pp. B.56; H.6-H.7. The working draft of the proposed permit required a continuous emission monitoring system (“CEMS”) to measure NOx emissions from the package boilers. Nucor challenged the use of CEMS for the package boiler and the LDEQ eliminated this requirement, citing 40 CFR 60.44b(j). This cite is a New Source Performance Standard, a separate regulatory

requirement, which is irrelevant to the subject PSD requirements. The PSD permit must be revised to incorporate appropriate monitoring and recordkeeping requirements to assure continuous emission reductions.

LDEQ Response to Comment No. VII.16

NO_x emissions were based on a manufacturer's guarantee of 0.00324 lb/MM Btu. Low NO_x burners (LNB) typically limit NO_x emissions to between 0.03 to 0.04 lb/MM Btu, and the SCR control efficiency was estimated to be approximately 90%. Regarding the overall percentage of control, determining a control efficiency of LNB relative to older burners that will never be constructed is a meaningless exercise (i.e., basing uncontrolled emissions on an AP-42 factor or the like would simply inflate the percent reduction). Note, however, the selected BACT is far more stringent than the lowest reported BACT determination in the EPA RACT/BACT/LEAR Clearinghouse of 0.0109 lb/MM Btu.

LDEQ's BACT determinations are set forth in the table on pages 3 and 4 of the PSD permit. This table is also included as Specific Condition 2 of the PSD permit. Emission limits are set forth in both the Part 70 and PSD permits.

Requirements to conduct an initial performance test and to maintain daily records of fuel consumption represent appropriate monitoring and recordkeeping for the source.

Comment No. VII.17

The BACT determination for SO₂ emissions from DRI-109/209 is flawed and should be revised. The Preliminary Determination Summary concludes that BACT for SO₂ emissions from the package boilers is the use of "pipeline-quality natural gas." Specific Condition #6 limits the sulfur in the natural gas to 2,000 grains of sulfur per million standard cubic feet of gas ("gr/MMscf"). However, this BACT determination is unenforceable and inconsistent with the emission calculations. Sulfur content of natural gas varies widely, depending upon the field it comes from and any preconditioning that occurs. *See* Center for Energy Economics, Interstate Natural Gas - Quality Specifications & Interchangeability, December 2002. The DRI PSD permit should be revised to incorporate a specific condition requiring Nucor to assure -- and keep records -- that only natural gas containing less than 2,000 gr/MM scf is purchased and burned by Nucor.

LDEQ Response to Comment No. VII. 17

A condition requiring Nucor to purchase natural gas with a sulfur content less than 2000 grains per million standard cubic feet of gas will be added to the Title V permit. Corresponding monitoring and recordkeeping requirements will also be included.

Comment No. VII. 18

The BACT determination for CO and VOC emissions from DRI-109/209 is flawed and should be revised. The Preliminary Determination Summary concludes that BACT for CO and VOC emissions from the package boilers is the use of "good combustion practices." This determination does not satisfy BACT for these pollutants. Further, even assuming it did, these BACT determinations are not enforceable.

First, the BACT analyses only evaluated a single control option for CO and VOC emissions - good combustion practices - assumed to reduce CO and VOC emissions by

50%. Oxidation catalysts, a post-combustion control, are commonly used on gas-fired sources to remove up to 90% of both CO and VOC emissions. Thus, an oxidation catalyst is a more efficient technology to reduce CO and VOC emissions and should therefore establish BACT for the package boilers.

Second, the phrase “good combustion practices” is ambiguous and thus not practically enforceable. It can mean different things to different people and encompass a wide range of practices. Does it, for example, require that the boilers be tuned to minimize CO and VOC, which would maximize NO_x? What effect does this determination have on the NO_x BACT determination? The U.S. EPA has developed guidance on good combustion practices. *See* U.S. Environmental Protection Agency, Good Combustion Practices; available at <http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf>. The DRI PSD permit -- and consequently the DRI Part 70 permit -- should be revised to include a specific condition defining the term “good combustion practices” and stating the specific practices that will be considered good combustion practices.

Third, Specific Condition #2 in the DRI PSD permit -- and Specific Requirements #100 and #254 in the Part 70 permit -- establishes an emission limit of 0.039 lb/MMBtu for CO. The PSD permit must include appropriate monitoring and recordkeeping requirements to assure that BACT emission limits and conditions are met on a continual basis at all levels of operation. NSR Manual, p. B.56. Continuous emission monitoring systems are routinely used to monitor CO emissions from natural gas fired sources. The PSD permit should be revised to incorporate a requirement to install and operate a CO CEMS or LDEQ should adequately explain its rationale for requiring only a single stack test over the life of the facility when more frequent testing is commonly specified and is technically feasible.

Fourth, the Specific Conditions in the DRI PSD permit -- and consequently the Specific Requirements in the Part 70 permit -- do not include any emission limitations for VOCs. BACT is an emission limit based on the maximum degree of reduction that is achievable. Specification of a control technology alone satisfies BACT only if there are technical impediments to the measurement of emissions. This is not the case here as the “Emission Rates for Criteria Pollutants” table in the Part 70 permit includes VOC emission rates in pounds per hour and tons per year. The Specific Conditions should be revised to include VOC emission limitations and a monitoring/recordkeeping requirement to assure continuous compliance with BACT for CO and VOC emissions.

LDEQ Response to Comment No. VII.18

LDEQ considers “good combustion practices” to include monitoring for flue gas oxygen, combustion air flow, fuel flow, and flue gas temperature, and maintaining these parameters at appropriate levels for efficient combustion. Specific requirements to install such sensors have been added to the permits for clarity. Nucor must maintain these parameters within the manufacturer’s recommended operating guidelines or as established during the initial performance test. No later than 90 days after the initial performance test, Nucor shall submit the appropriate ranges to LDEQ for incorporation into the permit.

VOC emission limits are set forth in both the Part 70 and PSD permits (see Specific Condition 6 of the PSD-LA-751).

Contrary to the commenter’s assertion, BACT does not always require “continuous emissions monitors,” or CEMS. In the case of the package boilers, potential emissions of CO total 41.54 tons

per year (TPY) each; thus, CEMS are not warranted.

Catalytic oxidation was not considered due the potential CO and VOC emissions from each package boiler, which total only 46.24 tons per year each, and the negative economic and environmental impacts associated with its use in the instant case. Conservatively assuming a 90% control efficiency, 41.66 tons per year of pollutants could be removed. However, catalytic oxidizers have an auxiliary fuel requirement and electrical demand. Thus, this reduction would be offset to some extent by the CO and VOC generated by combusting additional natural gas. NO_x and CO₂ emissions would also increase. Further, in order to make such a reduction cost-effective from a BACT standpoint, annualized costs would have to be very low for a unit designed to handle 73,116 actual cubic feet per minute of flue gas.

Comment No. VII.19

Permit No. PSD-AL-751 does not assure that BACT will be employed for the Reformers (DRI-108/208). The Reformer generates a reducing gas that is used in the Shaft Furnace to convert iron oxide into metallic iron. The reducing gas is primarily carbon monoxide and hydrogen. The spent reforming gas that leaves the Shaft Furnace is referred to as “top gas.” A portion of this top gas is blended with natural gas and combusted as fuel in the Reformer. The flue gases from combusting this mixture are emitted at the Reformer/Main Flue Gas Stack.

A portion of the spent reformer flue gases is diverted for use elsewhere in the facility, prior to treatment to remove NO_x. The emission calculations indicate that about 0.7% is diverted for use as upper seal gas (DRI-106/206); about 0.9% is diverted to the DRI storage silos (DRI-112/212); and about 1% is diverted for bottom seal gas, which is discharged during furnace dedusting (DRI-107/207). Thus, the BACT analysis for SO₂, CO, and VOCs is essentially identical for these four sources.

Specific Requirements in the DRI Part 70 permit include emission limitations for PM₁₀, NO_x, and CO emissions from DRI-108/209 that are expressed as “... lb/MMBtu as adjusted for seal gas system off-take portion from total Reformer flue gas generated by combustion fuel gases.” This phrase does not occur in the DRI PSD permit and standing alone in the Part 70 permit, makes no sense. It must be defined in the Specific Conditions of the PSD permit.

Generally, the BACT determinations in the DRI PSD permit are not supported by any technical supporting documentation in the record available for public review. The Preliminary Determination Summary discusses emissions from the reformer, but Nucor's application makes it clear that Nucor is considering DRI technology that does not include a reformer. As an initial matter, this inconsistency leaves the public unable to comment on the emissions from, and best available control technologies for, a reformer-less DRI process, because the Preliminary Determination Summary provided no discussion of that process. More fundamentally, the record contains no technical support documentation that would allow the public to provide fully-informed comments as to any type of DRI process. There are no AP-42 emission factors or industry guidance published by EPA describing emission sources, emission rates and typical control technologies for DRI processes. All the information is literally locked in the hands of the DRI process vendors, who likely have material balances derived from their own engineering design modeling, not to mention emission testing from full-scale and pilot plants overseas. It would be irresponsible for Nucor to commit to constructing the DRI process -- and to put LDEQ and the public to the task of reviewing the air quality impacts from the process- without

having obtained such data and engineering from the vendors. We suspect that Nucor in fact has such data and engineering. Indeed, Nucor's application to modify the pig iron Part 70 permit indicates that Nucor has received data or engineering literature from a pilot-scale test of SCR on a sinter plant in Austria -- but Nucor apparently did not provide this data to LDEQ. Based on the materials available for public review, the DRI process, and even more so the reformer-less DRI process, are "black-boxes." This does not provide for the type of informed public participation in the decision making process required by PSD. *See* 42 U.S.C. § 7470(5). LDEQ should require Nucor to submit technical documentation supporting the emission sources and emission rates for the DRI process and the available control technologies therefore.

LDEQ Response to Comment No. VII.19

The applicant addressed the commenter's concerns specifically in the permit application submitted to LDEQ. Specifically, it was noted that the installation of active control technologies to these very small sources of emissions were economically infeasible in a fundamental sense, and were likely to generate more pollution themselves than would be controlled in the attempt to capture these minor emissions.

The lack of AP-42 emissions factors for DRI facilities is likely due to the fact that these facilities represent newer technology that has not been domestically developed in earnest. As the commenter has noted frequently in previous comments, AP-42 is not necessarily the best source of emission factor data (and one the commenter has gone to great effort to criticize), yet it is frequently relied upon for prevalent and well-understood emission sources. Direct vendor data, or existing source emissions testing, are generally preferred over AP-42. The applicant presented vendor data as part of the permit application for the DRI facility. It is incumbent upon the applicant to adhere to the emission rates presented in the permit application and reflected in the draft permit.

Neither Nucor, nor the vendors are obligated to submit design specifications and such for public review. Often this information is highly proprietary. When emissions and permitted emission limits are based upon vendor guarantees and such, the permit applicant is required to comply with these standards.

The reformer-less DRI process has not been built or operated on a scale such has been proposed by Nucor, and should therefore be considered in the experimental phase for this application. The reformer-less design has not been considered as an alternate scenario or submitted as part of the current permit application.

Comment No. VII.20

The BACT determination for PM₁₀/PM_{2.5} emissions from DRI-108/208 is flawed and should be revised. The Preliminary Determination Summary concludes that BACT for the Reformer/Main Flue Gas Stack is a high-energy wet scrubber capable of removing 99% of the PM₁₀. There are several deficiencies with this determination.

First, the DRI PSD permit -- and consequently the Part 70 permit -- does not require that this technology be installed. The technology upon which the BACT emission limit is based must be specified in both permits. *See* NSR Manual, p. B.56.

Second, Specific Condition #2 express BACT for PM₁₀ as a limit of 0.0027 gr/dscf, which is inconsistent -- both in units and in the actual mass emission rate -- with the 0.010 lb/MMBtu limit expressed in Specific Requirements #83 and #237 in the Part 70

permit. Moreover, the BACT emission limit in the PSD permit is expressed in terms of filterable PM10 (which can be determined by comparing the BACT emission limitation to the emission calculations in Addendum II of the DRI application, EDMS Doc. 7712779, p. 21, which is clearly based on filterable PM10). This form of emission limit is inappropriate under PSD, particularly where BACT is a wet scrubber. Specific Condition #2 should be revised to establish a limit on total PM10, which is the regulated PSD pollutant.

Third, the DRI PSD permit does not provide any link between the BACT determination of a 99% efficient scrubber and the established emission limit, nor any evidence or other technical documentation to support that the limits represent the maximum degree of reduction that is achievable.

Fourth, notwithstanding the above, the limits as stated are unenforceable as the monitoring is inadequate. The PSD permit must include appropriate monitoring and recordkeeping requirements to assure that BACT emission limits and conditions are met on a continual basis at all levels of operation. NSR Manual p. B.56. The PSD permit purports to incorporate the monitoring and recordkeeping requirements from the Part 70 permit. This is inappropriate and in violation of the Clean Air Act, but even if such incorporation were allowed, a single stack test over the life of the facility is not adequate to assure continuous emission reductions or protection of short-term ambient air quality standards (the 24-hour PM10 and PM2.5 standards).

Fifth, Step 1 fails to list all applicable control options. Ammonia and sulfuric acid mist emitted by the SCR contribute to both PM10 and PM2.5. Thus, these emissions can be reduced by designing the SCR to meet a lower ammonia slip and by specifying an SCR catalyst with a low SO₂-to-SO₃ conversion. These options were not considered in the Reformer BACT analysis.

Last, the DRI PSD permit must -- but does not -- provide a separate BACT determination and establish a separate BACT limit for PM2.5.

LDEQ Response to Comment No. VII.20

BACT selection was listed clearly in a table in Page 3 and 4 of the PSD permit. This table is included in Specific Condition No. 2 of the PSD permit.

The commenter is in error, PSD-LA-741 makes clear that a high-energy wet scrubber has been selected as BACT. Numerical emission limits on the basis of this determination have also been listed in the PSD permit specific conditions.

Specific Condition #2 represents a directly measurable emission rate which is based upon the 0.01 lb/MMBtu limit cited by the commenter, and the volumetric emission rate from the source represented by the applicant. The inclusion of both an absolute particulate loading requirement, and a fuel-based emission metric work together to provide a conservative framework for determining compliance. The permittee shall comply with both limits.

The commenter appears to have a fundamental misunderstanding of the purpose and placement of the wet scrubber. The scrubber is used to clean spent reducing gas (top gas) used as fuel in the reformer, prior to combustion. This controls mineral dusts in the top gas that would otherwise pass through the combustion chamber of the reformer and be emitted to the atmosphere. As such, the scrubber would not be in a position to affect potential emissions attributable to the SCR.

Nucor provided a top-down BACT analysis for PM_{2.5} and the requisite modeling analyses to demonstrate that the facility's emissions will not result in violations of the annual and 24-hour PM_{2.5} NAAQS. A combined PM₁₀/PM_{2.5} analysis is sufficient where it demonstrates that both pollutants are being controlled to BACT levels. The commenter has presented no evidence showing that this demonstration is inadequate.

LDEQ has included PM_{2.5} limitations in the final permits.

Comment No. VII.21

The BACT determination for NOx emissions from DRI-108/208 is flawed and should be revised. The Preliminary Determination Summary concludes that BACT for NOx for the Reformer/Main Flue Gas stack is low-NOx fuel combustion combined with low-NOx burners and SCR. We support the use of low NOx fuel, SCR, and low NOx burners to control NOx from the Reformer/Main Flue Gas Stack. However, there are several problems with the translation of these controls in the DRI PSD permit.

First, although the DRI Part 70 permit includes a specific requirement to install SCR on the reformer/main flue gas stack, the Specific Conditions in the DRI PSD permit do not. This violates 42 U.S.C. § 7475(a), pursuant to which the PSD permit must assure that the source will employ BACT. And when there is no technical impediment to measuring emissions, as is the case here, the PSD permit must include specific conditions specifying both the BACT emission limit and the control technology that must be employed continuously to achieve that limit.

Second, as explained above, there is no thread connecting the technology determinations with the BACT emission limits. The emission limits did not arise out of a top-down BACT determination. It is impossible to confirm, based on the permit record, that any NOx limitation represents the maximum degree of reduction that is achievable. It is unclear, for example, whether either of these limits include the 50% reduction due to low NOx fuels, the 50% reduction due to low NOx burners, and the 90% reduction due to the SCR. These three controls combined would reduce NOx from the uncontrolled level by 97.5%. The emission calculations, on the other hand, indicate that the proposed emission limitations correspond to a 90% reduction from an "uncontrolled level," but fails to state what it is uncontrolled relative to. Thus, it is uncertain whether the emission limitations proposed for this source are based on the maximum degree of reduction that is achievable.

Finally, a BACT determination must be enforceable as a practical matter and must assure continuous emission reductions. The PSD permit must include appropriate monitoring and recordkeeping requirements to assure that BACT emission limits and conditions are met on a continual basis at all levels of operation. NSR Manual p. B.56. The PSD permit must be revised to incorporate appropriate monitoring and recordkeeping requirements to assure continuous emission reductions.

LDEQ Response to Comment No. VII.21

This comment for the reformers is materially the same as Comment No. VII. 16 directed to the package boilers. See LDEQ Response to Comment No. VII. 16 for our response to Comment No. VII. 21, with reference to draft PSD permit PSD-LA-741, pg. 45.

Comment No. VII. 22

The BACT determination for SO₂ emissions from DRI-108/208 is flawed and should be revised. Top gas from the Shaft Furnace is blended with about 38% natural gas and combusted as fuel in the Reformer. The Preliminary Determination Summary concludes that BACT for SO₂ emissions from the Reformer/Main Flue Gas Stack is the removal of hydrogen sulfide from the top gas fuel using acid gas scrubbing (assumed to remove 95% of the sulfur) and the use of natural gas containing no more than 2,000 gr/MMscf of gas. There are several problems with this determination.

First, the Specific Conditions in the DRI PSD permit -- and consequently the Specific Requirements in the Part Permit -- do not explicitly require the use of acid gas scrubbing of the top gas. The technology upon which the BACT emission limit is based must be specified in both permits. *See* NSR Manual, p. B.56. The Preliminary Determination Summary states that “Nucor will install an acid gas scrubbing system for top gas prior to its use as fuel in the reformer” but goes on to state that “BACT for natural gas is to purchase natural gas containing no more than 2000 grains of Sulfur per MMscf.” Specific Condition #6 echoes this limit for natural gas sulfur content, but it does not require the installation of an acid gas scrubbing system for top gas. More fundamentally, the PSD permit does even not *require* Nucor to use top gas as fuel in the reformer. A plain reading of the PSD permit is that Nucor does not need to install an acid gas scrubbing system for top gas so long as Nucor does not use top gas as fuel in the reformer.

The Part 70 permit provides evidence that in fact that Nucor does not intend to burn top gas in the reformers. Specific Requirements # 81-82 and 235-236 in the Part 70 permit state that “BACT is Natural has ≤ 13 MM BTU per Tonne of Direct Reduced Iron (DRI) produced” and require Nucor to keep records of DRI production and natural gas usage. Nucor's emission calculations indicate that the normal reformer natural gas firing rate will be 1,521 MMBtu/hour, which represents a nominal natural gas supplement rate of 38.24%. Given that a reformer will produce 2.5 MM tonnes of DRI per 8,000 hour year, the emission calculations on page 21 of EDMS Doc. 7712779 indicate that the normal total heat input to each DRI furnace will be 12.7 MMBtu/tonne (= 1,521 MMBtu/hr \div 0.3824 = 312.5 tonnes/hr). In other words, according to the Part 70 permit, BACT for the reformers is to burn as much natural gas as the reformers can handle. And what happens to the top gas when the reformers burn only natural gas? According to the Preliminary Determination Summary, it will be flared -- which results in completely uncontrolled emissions. The Part 70 permit, however, cannot establish BACT, which must be established in the PSD permit first and then incorporated into the Part 70 permit. The DRI PSD permit must be revised to include Specific Conditions that Nucor construct the acid gas absorption systems (and acid gas vent treatment systems) before commencing operation of the DRI process, and limiting the use of supplemental natural gas to prevent any unnecessary flaring of top gas.

Second, there is no evidence in the permit record that the emission limitations that are set indeed represent 95% reduction in sulfur content of the top gas. The emission calculations start with an unsupported assumption of a concentration of 2.98 mg SO₂/Nm³ in the exhaust gases. This reveals nothing about the uncontrolled sulfur content of the top gas or the control efficiency of the top gas scrubber. Thus, there is no evidence that BACT will be achieved for SO₂ emissions from the Reformer Main Flue Stack.

Third, the Preliminary Determination Summary and the records available for public review do not provide sufficient detail to faithfully perform a top-down BACT analysis

for this source. The analysis includes discussions of both fuel treatment for the removal of hydrogen sulfide and other sulfur compounds from top gas as well as flue gas desulfurization for the removal of SO₂ from post-combustion flue gases. The analysis ranks acid gas absorption as having a higher control efficiency (95%) than a wet scrubber (90%). This ranking probably is in error, but more technical information is necessary in order to rank the control technologies as required by PSD. There is a significant body of technical literature which indicates that a wet scrubber should be able to remove up to 99% of the sulfur dioxide from the reformer flue stack, which would have characteristics not unlike any other fuel burning unit. Acid gas absorption, on the other hand, would consist of an unspecified amine absorber installed in the top gas fuel line itself -- not the reformer stack -- and would result in hydrogen sulfide emissions from the acid gas absorption vent that Nucor proposes to control using an unspecified catalyst. Acid gas absorption may indeed be the best available technology for reducing SO₂ emissions from the reformer, but the record provides no indication that it has been used on DRI reformers - which, unlike for example refinery fuel gas systems, may contain significant quantities of iron and other metals -- and no technical documentation fully to evaluate its use here. Nucor should be required to provide technical support documentation for the specific amine system' and acid gas absorption vent sulfur control system, for public review and comment.

Fourth, even if a limit of 13 MMBtu of natural gas per tonne of DRI produced were BACT for SO₂ emissions from the reformers, which is not the case, a BACT limit cannot be based on a 12-month rolling average, as suggested by Specific Requirements #81 and 236. BACT emission limits must assure compliance with short-term ambient standards, demonstrated in the source impact analysis at LAC 33:III.509.K, and may *never* be based on a 12-month average. See Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and § 112 Rules and General Permits, Kathie A. Stein, Jan. 25, 1995, p. 9. The PSD permit must be revised to incorporate an averaging time for compliance, which may then be incorporated into the Part 70 permit. This averaging time must be appropriate for assuring compliance with the 1-hour SO₂ ambient standard, and under no circumstances longer than one-month. See, e.g., EPA's Review of Proposed Title V Permits for Florida Power & Light, December 11, 1997, Enclosure 1, Objection 2 ("The Manatee permit requires an annual emission test to verify compliance with the applicable three-hour particulate emission standard. It has not been demonstrated that an annual emission test alone will constitute the basis for a credible certification of compliance with the particulate emission standard for units 001 and 002.").

Eighth, we believe the emphasis on limiting the sulfur content of natural gas is misplaced as most of the SO₂ released at the Reformer Main Stacks originates in the top gas, not the natural gas. Specific Condition # 2 provides that the emission limitation corresponding to BACT for the reformers is 0.002 pounds of SO₂ per MMBtu. In comparison, the emission rate from burning natural gas with a sulfur content of 2000 gr/MMscf is 0.00056 pounds of SO₂ per MMBtu. As BACT was concluded to be acid gas scrubbing of the top gas, limits should be placed on the sulfur and heat contents of the top gas -- not just on the sulfur content of the natural gas -- and Nucor should be required to continuously monitor the sulfur and heat content of the top gas (given the nature of the process that generates top gas). In addition, the BACT emission limit in Specific Condition #2 should be presented in terms of pounds per hour or pounds per tonne of DRI produced, rather than pounds per MMBtu, and the calculation of the BACT emission limit should be explicit and verifiable as to emissions from natural gas combustion vs. emissions from top gas combustion. Last, under any circumstances, operating limits should be established for the acid gas absorber.

LDEQ Response to Comment No. VII.22

BACT selection was listed clearly in a table in Page 3 and 4 of the PSD permit. This table is included in Specific Condition No. 2 of the PSD permit.

This comment for the reformers has portions that are substantially the same as Comment No. VII. 17 directed to the package boilers. See LDEQ Response to Comment No. VII. 17 for our response to Comment No. VII. 22, with reference to draft PSD permit PSD-LA-741, pg. 52.

Additionally, the commenter insinuates that the applicant would be allowed to operate the facility without installing and operating an energy integration design, in the form of a system using spent top gas as fuel, and could therefore avoid the installation of an acid gas scrubbing system. An energy integration design is required as BACT for emissions of CO₂e, as document in draft PSD permit PSD-LA-741, p. 49, and may not be avoided by the facility under the proposed permits. The requirement to consume natural gas at a rate of 13 MMBtu / tonne of DRI or less, is the metric that determines compliance with the established BACT limitation.

The proposed 95% control efficiency for SO₂ due to the acid gas absorber is not from the direct control of SO₂ itself. Rather, it is due to the absorption of the H₂S that is contained in the top gas fuel, which prevents the formation of SO₂ when that cleaned fuel is then combusted. The use of amine-based absorption systems to remove H₂S from gaseous streams is commonplace in the petroleum industry, and LDEQ has a great deal of experience with such systems in those applications. LDEQ finds the transfer of this technology to the DRI application to be reasonable, and one that is additionally supported by the fact that the acid gas scrubber is primarily in place to separate CO₂ from the spent reducing gas. The capacity of this device to serve a high degree of control to multiple pollutants simultaneously is viewed by LDEQ as an innovative application of existing technology, ultimately providing additional energy, economic and environmental benefits over an approach utilizing separate devices. The commenter's concern about iron metals interfering with the operation of amine-based H₂S capture is unwarranted in light of the fact that the catalysts used to convert H₂S into elemental sulfur are largely iron-based.

The limit of ≤13 MMBtu / tonne of DRI is not BACT for emissions of SO₂. This limit is BACT for emissions of CO₂e. Comments to the contrary are flawed in this respect.

Limits on the sulfur content of natural gas are only a part of the BACT determination, as the commenter has noted in detail throughout the comment. LDEQ agreed with the determination of the applicant that, due to the variability of sulfur content in iron ores, BACT should be 95% control of sulfur compounds in the top gas fuel through the application of acid gas absorption. Due to the nature and quantity of these emissions, a specific limit on uncontrolled sulfur content in the top gas fuel is not warranted.

Comment No. VII.23

The BACT determination for CO and VOC emissions from DRI-108/208 is flawed and should be revised. The Preliminary Determination Summary concludes that BACT for both CO and VOC emissions from the Reformer/Main Flue Gas Stack is good combustion practices. There are several problems with these determinations.

First, the BACT analyses only evaluated a single control option for CO and VOCs - good combustion practices, assumed to reduce CO and VOC by 50%. There are at least two other technically feasible options that should have been evaluated: (1) oxidation catalysts

and (2) more efficient acid gas absorption. Oxidation catalysts, a post combustion control, are commonly used on gas-fired sources to remove up to 90% of both CO and VOCs. Thus, an oxidation catalyst is the top technology and should have been evaluated in the top-down BACT analysis. The CO and VOC emissions from the Reformer Main Flue Gas stack originate from slight absorption in the amine treating of the top gas. The top-down BACT analyses should have evaluated optimizing the amine treating unit to improve the absorption of CO and VOCs in the amine solution.

Second, the phrase “good combustion practices” is ambiguous and thus not practically enforceable. It can mean different things to different people and encompass a wide range of practices. Does it, for example, require that the burners in the reformer be tuned to minimize CO and VOC, which would maximize NO_x? What effect does this determination have on the NO_x BACT determination? The U.S. EPA has developed guidance on good combustion practices. See U.S. Environmental Protection Agency, Good Combustion Practices; available at <http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf>. The DRI PSD permit -- and consequently the DRI Part 70 permit -- should be revised to include a specific condition defining the term “good combustion practices” and stating the specific practices that will be considered good combustion practices.

Third, the CO and VOC BACT emission limitations in Specific Condition #2 -- and consequently also in the Part 70 permit -- are not enforceable as a practical matter as the emission limits are not accompanied by an averaging time and the monitoring is inadequate. The PSD permit must include appropriate monitoring and recordkeeping requirements to assure that BACT emission limits and conditions are met on a continual basis at all levels of operation. NSR Manual p. B.56. Continuous emission monitoring systems are routinely used to monitor CO emissions from natural gas fired sources. The PSD permit should be revised to incorporate a requirement to install and operate a CO CEMS or LDEQ should adequately explain its rationale for requiring only a single stack test over the life of the facility when more frequent testing is commonly specified and is technically feasible.

Fourth, the Specific Conditions in the DRI PSD permit -- and consequently the Specific Requirements in the Part 70 permit -- do not include any emission limitations for VOCs. BACT is an emission limit based on the maximum degree of reduction that is achievable. Specification of a control technology alone satisfies BACT only if there are technical impediments to the measurement of emissions. This is not the case here as the “Emission Rates for Criteria Pollutants” table in the Part 70 permit includes VOC emission rates in pounds per hour and tons per year. The Specific Conditions should be revised to include VOC emission limitations and a monitoring/recordkeeping requirement to assure continuous compliance with BACT for CO and VOC emissions.

Fifth, there is no support for the emission factors used to calculate emissions of CO (0.04 lb/MMBtu) and VOC (0.005 lb/MMBtu) and which are stated as BACT for the Reformer. These factors simply appear with no citations to literature, emission compilations, stack tests, or vendor guarantees. Thus, it is not possible to confirm that they correspond to a 50% reduction achieved with good combustion practices, nor is it feasible to ascertain the specific combustion practices assumed to reach these levels.

LDEQ Response to Comment No. VII.23

This comment for the reformers is materially the same as Comment No. VII. 18 directed to the package boilers. See LDEQ Response to Comment No. VII. 18 for a portion of our response to

Comment No. VII. 23.

The commenter's assertion that CO and VOC emissions "originate from slight absorption in the amine treating of the top gas" is puzzling. The majority of the spent reducing gas that passes through the acid absorber is mixed with natural gas and recycled to the reformer to generate additional reducing gas. A smaller portion is diverted to the reformer burners, where the carbon monoxide is combusted as a primary fuel. Aside from the fact that direct combustion is more efficient than either of the options presented by the commenter, carbon monoxide is a primary reactant in the reducing furnace and removing it from the process gas recycle loop would fundamentally impair the efficiency of the process. Such a design would therefore be at odds with the BACT determination for emissions of GHG. Energy integration, or the combustion of a portion of the spent reducing gas in the reformer, is a design requirement of the BACT determination for emissions of GHG.

The emission factor for VOC from the reformers is a direct unit conversion of the AP-42 factor for natural gas combustion. Due to the reformers burning carbon monoxide as a primary fuel, emissions of carbon monoxide are determined by the unit design, and emission factors were supplied by the vendor.

Comment No. VII.24

Permit No. PSD-LA-751 does not assure that BACT will be employed for the Upper Seal Gas Vents (DRI-106/206). A portion of the cooled flue gas from the Reformer discussed above is used to "seal" the Shaft Furnace and to prevent reducing gas from escaping. A portion of this seal gas is used to maintain a gas seal underneath the charge hopper at the top of the Furnace and a portion is used to maintain the seal above the product discharge point at the bottom of the Furnace. The upper seal gas is discharged at the Upper Seal Gas Vent, discussed here. The lower seal gas is discharged at the Furnace Dedusting Scrubber, discussed below in comments below.

First, the process descriptions for top seal gas are unclear and not consistent between the DRI Application and the DRI PSD permit. In addition, neither provides sufficient information to understand the process flow of the seal gas. These discrepancies and ambiguities make it very difficult, if not impossible, for LDEQ and the public to confirm whether BACT will in fact be employed for this source.

The process flow diagram provided in the DRI Application shows the seal gas routed via two streams:

- 1) the top seal gas is routed via the Reactor Charge Hopper from where it is discharged to either
 - a) the Reactor (aka Shaft Furnace), or
 - b) to the atmosphere through the Upper Seal Gas Vent (aka Charge Hopper); and
- 2) the bottom or lower seal gas is routed via the Product Discharge to either
 - a) the Furnace Dedusting Scrubber from where the scrubbed gas is discharged to the atmosphere, or
 - b) the DRI Conveying, DRI Silos, and DRI Silos Scrubber from where the scrubbed gas is discharged to the atmosphere. (See Figure 1 below).

See Figure 1 Zen-Noh Comments

The process flow diagram provided by the DRI Application (excerpted and adapted in

Figure 1 above) fails to identify where in the process the seal gas is drawn off from the cooled flue gas from the Reformer. The DRI PSD permit states that seal gas is removed before the flue gas is treated for NO_x control, *i.e.*, before the SCR, because ammonia from the SCR would cause clumping of the product which would lead to significant process upsets. The PSD permit further states that BACT for VOC and CO were already determined as good combustion practices for the Reformer flue gas and so no additional control is feasible for the small use of this flue gas as a seal gas. The PSD permit further states that BACT for SO₂ and particulate matter was determined to be treatment of the spent reducing gas being sent to the Reformer as combustion fuel and so no additional control is feasible for the seal gas. The PSD permit notes that all of the spent reducing gas is controlled for particulate matter but only the portion that is sent for combustion in the Reformer is treated for SO₂ emissions. It is unclear what the statements about the SO₂ and particulate matter control of spent reducing gas have to do with the seal gas, as the spent reducing gas is routed to the Reformer and the seal gas is drawn off at the Reformer combustion side, *i.e.*, before treatment at the main flue gas stack. Given all these inconsistencies and ambiguities, Nucor should be required to submit more detailed process flow diagrams and heat and material balances, so that LDEQ and the public may have an opportunity to confirm that BACT will be employed.

Second, the DRI Application contains separate top-down BACT analyses for each pollutant. These analyses all conclude that BACT is a technology: PM₁₀/PM_{2.5} - high-energy wet scrubber for top gas fuel to reformer; NO_x - low NO_x burners and low NO_x fuel combustion; SO₂ - acid gas scrubbing of top gas fuel to reformer; and CO - good combustion practices. No BACT analysis is presented for VOCs.

The definition of BACT is an emission limitation based on the maximum degree of reduction. The BACT analyses do not establish an emission limitation for any of these pollutants. Rather, emission limits are calculated separate from the top-down BACT analyses, based on certain unsupported assumptions, *e.g.*, emissions factors for NO_x and CO, PM₁₀/PM_{2.5} mass fractions, SO₂ concentration. The tons-per-year emission rates calculated with these unsupported assumptions are adopted by LDEQ as the BACT emission limits with no evidence that they represent the maximum degree of reduction that is achievable. There is no thread to link: the technology-based BACT determination with the tons-per-year emission rates specified as BACT. Thus, the BACT analyses for all of these pollutants are fundamentally flawed.

Third, the DRI PSD permit does not assure that BACT emission limits for the upper seal gas vents will be continuously met. BACT emission limits must be met on a continual basis at all levels of operation. This requires that the limits be expressed on an instantaneous basis (*e.g.*, lb/MMBtu or ppm or percent reduction), demonstrate protection of short-term ambient standards (limits written in lb/hr), and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and record-keeping procedures). *See* NSR Manual, p. B.56. Thus, the permit must be able to show compliance or noncompliance by monitoring and must specify a reasonable compliance averaging time. The proposed BACT emission limits for the Upper Seal Gas Vents do not meet any of these requirements.

Fourth, all emissions limits for the Upper Seal Gas Vent (and the Acid Gas Absorption Vents, discussed below) are blanket limits representing emissions caps and are expressed in tons per year. “Blanket emissions limits alone (*e.g.*, tons/yr, lb/hr) are virtually impossible to verify or enforce, and are therefore not enforceable as a practical matter.” *See* NSR Manual, p. c.4. The NSR Manual also indicates that limits must be written “in

such a manner than an inspector could verify instantly whether the source is or was complying with the permit condition. *Id.* Further, “it is best to express the emission limits in two different ways, with one value serving as an emissions cap (*e.g.*, lb/hr) and the other ensuring continuous compliance at any operating capacity (*e.g.*, lbs/MMBtu).” *See* NSR Manual, p. H.5.

Specific Condition #2 -- and consequently the DRI Part 70 permit -- should be revised to include pounds-per-hour limits based on a 1-hour average to demonstrate protection of the 1-hour NO₂ and SO₂ ambient air quality standards; to demonstrate compliance using continuous emissions monitoring where feasible; and additionally to include limits in lb/MMBtu, parts per million, or other instantaneous concentration metric.

Fifth, averaging times should be added to the tons-per-year limits. As stated, notwithstanding the absence of any monitoring, compliance would only be determined at the end of each year. And even with monitoring, no compliance determination could be made until the end of the first year of operation. Guidance by the U.S. EPA recommends that rolling annual averages be calculated on a daily basis unless not feasible. “EPA policy expresses a preference toward short term limits, generally daily but not to exceed one month.” Memorandum from John S. Seitz and Robert I. van Heuvelen, U.S. Environmental Protection Agency, to Directors, Re: Options for Limiting the Potential to Emit (PTE) of a Stationary Source under Section 112 and Title V of the Clean Air Act, January 25, 1995; *see also* Memorandum from Terrell E. Hunt to John S. Seitz, Re: Guidance on Limiting Potential to Emit in New Source Permitting, June 13, 1989 (“However, for these limitations [on production or operation] to be enforceable as a practical matter, the time over which they extend should be as short term as possible ...”); U.S. Environmental Protection Agency, Region 5, Air & Radiation Division Issue Paper, August 19, 1992, Proposed Paint Shop for GM Truck & Bus Group-Moraine Assembly Plant, Dayton, Ohio (advising that “annual limits [referring to coating usage] should be rolled daily unless the company provides justification to why it is infeasible to monitor the limiting parameter daily”).

Sixth, the regulated PM₁₀ and PM_{2.5} parameters are total particulate matter, expressed as the sum of the filterable and condensable fractions. Yet, the emission rates, adopted as BACT for PM₁₀ and PM_{2.5}, are reported only as filterable PM₁₀ and filterable PM_{2.5}. The BACT emission rates in Specific Condition #2 -- and consequently in the Part 70 permit -- should be expressed in terms of total particulate matter.

Seventh, Specific Condition #2 does not contain any limitations on the emissions of VOCs. The permit record should be revised to explain and justify this omission, or BACT emission limits for VOCs should be included in Specific Condition #2 -- and consequently in the Part 70 permit.

LDEQ Response to Comment No. VII.24

Due to the fact that emissions of NO_x, SO₂, CO and VOC are generated at the reformers, a small portion of which is then vented as seal gas, specific requirements addressing BACT for these pollutants is properly addressed in the Title V permit at the reformers. Redundant requirements at the end use points of the seal gas would not be conducive to a permit with clear and enforceable conditions for which compliance can be demonstrated at the source with the listed specified requirement (*e.g.* use of Low-NO_x fuel at the product silos, which do not themselves engage in combustion).

The commenter's assertion that condensable particulate matter was not addressed by emission calculations is in error, the calculation of emissions from reformer flue gas, used as seal gas, clearly include the condensable fraction.

Comment No. VII.25

Permit No. PSD-LA-751 does not assure that BACT will be employed for Furnace Dedusting (DRI-107/207). A portion of the cooled flue gas from the Reformer discussed above is used to "seal" the Shaft Furnace and to prevent reducing gas from escaping. A portion of this seal gas is used to maintain a gas seal at the top of the Furnace and a portion is used to maintain a gas seal above the product discharge point at the bottom of the Furnace. The upper seal gas is discharged at the Upper Seal Gas Vent, discussed above. The lower seal gas is discharged at the Furnace Dedusting Scrubber, discussed here.

First, the gases discharged with the DRI product are seal gas and spent reducing gas, plus entrained particles from pellet interaction. Seal gas is spent reducing gas. And spent reducing gas is Reformer combustion gases that have not been treated to remove NO_x. Thus, the BACT determinations for Furnace Dedusting (DRI-107/207), expressed as a concentration (lb/MMBtu), should be identical to the Reformer/Main Flue Gas Stack (DRI-108/109) for all pollutants except PM₁₀/PM_{2.5} (due to the pickup of particulate matter from the interaction of pellets) and NO_x (as the seal gas is withdrawn prior to the SCR). However, the Briefing Sheet does not identify any controls at all for Furnace Dedusting for any pollutant except PM₁₀. The draft PSD Specific Conditions for CO are identical for these two sources, as expected. But, the Specific Conditions do not set a BACT limitation on either SO₂ or VOC emissions from Furnace Dedusting. (Further, the draft Part 70 permit Specific Requirements do not set BACT limitations on SO₂ or VOCs). The Specific Conditions in the DRI PSD permit -- and consequently the Part 70 permit -- should be revised to include BACT emission limitations on SO₂ and VOCs that are identical to those for the Reformer Main Stack.

LDEQ Response to Comment No. VII.25

This comment is substantially the same as a portion of Comment No. VII. 24. Please see LDEQ Response to Comment No. VII. 24 for our response to this comment.

Comment No. VII.26

The BACT determination for NO_x and CO emissions from DRI-107/207 is flawed and should be revised. The BACT emission limitations for NO_x and CO in the DRI Part 70 permit Specific Requirements are expressed as " ... lb/MMBtu as adjusted for seal gas system off-take portion from total Reformer flue gas generated by combustion fuel gases." This phrase does not occur in the Specific Conditions of the DRI PSD permit and standing alone in the DRI Part 70 permit, makes no sense. It must be defined in both permits.

In addition, the emission calculations indicate that emissions from furnace dedusting were calculated from an emission factor expressed in lb/MMBtu and the Reformer firing rate, multiplied by the fraction (1.11%) of the total Reformer volumetric vent rate that is diverted to the seal gas system and subsequently released during furnace dedusting. This adjustment is applied to the emission rates in lb/hr and ton/yr, not the emission concentration in lb/MMBtu. The use of this factor should be explained in the Specific

Conditions and the fraction required as an enforceable condition.

This fraction determines the emission rates in lb/hr and ton/yr (as emissions are calculated by multiplying a lb/MMBtu emission factor by the Reformer firing rate and the off-take fraction) and thus has a direct impact on the modeled ambient concentrations. The NO_x and CO emissions that were modeled in the air quality analysis assume that only 1.1 % of Reformer volumetric vent rate, or 5,000 Nm³/hr, would be vented during furnace dedusting. However, there are no limitations in either the draft PSD Permit or the draft Title V Permit on the amount of seal gas that is used to seal the bottom of the Shaft Furnace and which is thus vented during furnace dedusting. As this seal gas stream is diverted before the Reformer combustion gases are treated to remove NO_x, this could potentially be a major source of NO_x emissions if more than 1.1 % of the untreated gas were diverted to seal the bottom of the Furnace.

LDEQ Response to Comment No. VII.26

This comment is substantially the same as a portion of Comment No. VII. 24. Please see LDEQ Response to Comment No. VII. 24 for our response to this comment.

Comment No. VII.27

The BACT determination for PM₁₀/PM_{2.5} emissions from DRI-107/207 is flawed and should be revised. The Preliminary Determination Summary concludes that BACT for Furnace Dedusting is a high energy scrubber achieving at least 99% control of PM/PM₁₀ that would be installed on the furnace discharge for DRI dust removal. The Specific Conditions in the DRI PSD permit -- and consequently the Specific Requirements in the DRI Part 70 permit -- establish the BACT emission limitation as 0.002 gr/dscf. There are several problems with this determination.

First, the Step 3 ranking is defective as it reports only the percent PM₁₀ removed, excluding the expected emission rate (e.g., lb/hr, lb/MMBtu) and the 'expected emission reduction. Hence, there is no link between the identified control technologies and the limit of 0.002 gr/dscf. The permit record contains no evidence that this limit, which was selected outside of the BACT analysis and is unsupported, represents the reported 99% control efficiency nor the maximum degree of reduction that is achievable. Instead, the emission calculations start with this controlled particulate concentration with no indication of how it was derived. The uncontrolled PM₁₀ and PM_{2.5} emissions from furnace dedusting should have been specified as the starting point for the BACT analysis. Absent this, there is no basis for concluding that 0.002 gr/dscf corresponds to the maximum degree of reduction in PM₁₀/PM_{2.5} from the subject sources. For example, if the uncontrolled PM₁₀ emission concentration were 0.2 gr/dscf, the proposed limit of 0.002 gr/dscf would correspond to 99%. However, if the uncontrolled PM₁₀ emission concentration were only half that, 0.1 gr/dscf, the proposed limit would correspond to only 80% control. The emission calculations start with a "cleaned gas particulate concentration" (i.e., already controlled) without any explanation of how this level was picked (it should have been selected in the BACT analysis) or relates to the required control technology.

Second, the regulated pollutant is total PM₁₀, comprising the sum of filterable plus particulate PM₁₀. It is unclear whether the proposed limit of 0.002 gr/dscf is total or only the filterable portion of particulate matter. The metric, gr/dscf, is generally only used for filterable particulate matter. The emission calculations indicate that furnace dedusting

will emit both filterable PM10 (0.004lb/MMBtu) and condensable PM10 (0.006 lb/MMBtu). In fact, the major portion of particulate matter is condensable. The BACT determinations did not include a top-down analysis for the condensable fraction (which would not be moved by the proposed wet scrubber) and the draft permits do not contain any BACT emission limitations for the condensable fraction. The condensable fraction could be controlled using sorbent injection.

Third, the Specific Conditions in the DRI PSD permit do not require that Nucor install the BACT control technology, but rather, only places limits on its operation in the form of a concentration and emission rates in lb/hr and ton/yr which are measured only once over the lifetime of the facility and an unspecified scrubber flow rate (0.00 gal/min). The Specific Conditions -- and consequently the Specific Requirements in the DRI Part 70 permit -- should be modified to require the installation of a 99% efficient scrubber.

Fourth, the Specific Conditions do not include any operating limits on the wet scrubber. The PSD permit must include appropriate monitoring and recordkeeping requirements to assure that BACT emission limits and conditions are met on a continual basis at all levels of operation. NSR Manual, p. B.56. Specific Requirements #61 and #219 in the DRI Part 70 permit allow Nucor to set a scrubber flow rate or pressure differential limit/range after the facility is built, under an administrative permit amendment. The Part 70 permit does not disclose the purpose of this operational limit, but presumably, it is being used as a surrogate for PM10 under the theory that the PM10 emission limits would be met if the scrubber were operating properly, although Specific Requirements #61 and #219 do not require any demonstration of a relationship between PM10 and the chosen operational parameters. No public review is required for an administrative amendment. BACT must be established in the PSD permit and incorporated into the Part 70 permit, not the other way around. As the scrubber flow rate/differential pressure are used to assure compliance with BACT determinations in a PSD permit -- and consequently with applicable requirements in the Part 70 permit -- which are individually subject to public review, these limitations are likewise subject to public review. Further, the Preliminary Determination Summary or Specific Conditions should explain the purpose of this limit and establish the resulting scrubber flow or pressure differential limits/ranges as enforceable conditions.

Fifth, the DRI Part 70 permit require only a single stack test over the life of the facility to determine compliance with the PM10 emission limit of 0.002 gr/dscf and the emission rates in lb/hr and ton/yr in the Emission Rates for Criteria Pollutants table. Compliance can only be determined if a stack test is conducted to directly measure the concentration of PM10/PM2.5 in the exhaust gases and the exhaust gas flow rate. The Part 70 permit only requires routine measurement and reporting of the scrubber flow rate. This reveals no information about PM10 concentrations expressed in gr/dscf or PM10 emission rates expressed in lb/hr and ton/yr, unless studies are conducted to establish a statistically valid relationship between flow rate and these emission metrics. Any such relationship would only be valid for the conditions under which it was developed. If the iron ore composition changed or process operating conditions change, any such relationship would change. Thus, the proffered BACT limits are not enforceable as a practical matter.

The DRI PSD permit -- and consequently the Part 70 permit -- should be revised to require at least annual stack testing to measure particulate emission limitations expressed as gr/dscf, lb/hr and ton/yr coupled with valid indicator monitoring.

Finally, the DRI PSD permit must -- but does not -- establish a separate BACT emissions

limit for PM_{2.5}.

LDEQ Response to Comment No. VII.27

This comment is substantially the same as a portion of Comment No. VII. 3. Please see LDEQ Response to Comment No. VII. 3 for our response to this comment.

At the design particulates loading and gas flow rate, the proposed scrubber achieves a minimum of 99 percent efficiency. At this level, a guarantee of 0.002 grains of particulates per standard cubic foot (gr/scf) of gas was made by the manufacturer. Compliance with the direct mass loading (gr/scf) is more efficient and cost effective than the relative values (percent of the input values). The limits are listed in Specific Condition 2 of the PSD permit and in the Specific Requirements of the Title V permit. Permittee must comply with this limit.

BACT selection was listed clearly in a table in Page 3 and 4 of the PSD permit. This table is included in Specific Condition No. 2 of the PSD permit. Compliance with the limit of 0.0022 gr/scf for PM deem compliance with the BACT limit for both PM, PM₁₀, and PM_{2.5}.

Compliance with the permit is demonstrated by an initial performance test and liquid flow rate monitoring. These requirements are deemed adequate to demonstrate compliance with the permit limits during the term of this permit.

Comment No. VII.28

Permit No. PSD-LA-751 does not assure that BACT will be employed for Screening and Transport (DRI-115/116). Direct reduced iron product is discharged from the Furnace (DRI-107/207), transferred by conveyor to screens to remove fines (DRI-115), and the screened DRI product is conveyed to Product Storage Silos (DRI-112/212). Particulate matter generated during these operations can be vented to atmosphere from conveyors, transfer stations, screening operations, and the storage silos.

The permit documents are a maze of confusing nomenclature and lack a clear process flow diagram. Screening and transport are combined in a general category called "Product Storage and Handling" in the DRI Application, the Briefing Sheet, and in the PSD Specific Conditions. They are included under "Furnace Dedusting" in the Preliminary Determination Summary, based on source identification numbers (DRI-115/116). However, in the Preliminary Determination Summary, the actual BACT determination for product transport is included under the heading "Storage Silo Dust Collection Including Product Transfers." The Part 70 permit Specific Requirements and emission calculations title these sources in yet a third way: "Product Screen Dust Collection" for screening (DRI-115) and "Screened Product Transfer Dust Collection" for conveyor transport (DRI-116), which presumably includes transfer stations. This renders the PSD and Part 70 permits ambiguous and hence unenforceable as it is not clear which source ID number (and hence which emission limits) corresponds to which emission units. Nor is it clear that all of the conveyors, transfer stations, and screens are included in the emission calculations, BACT determinations, and emission limits. A detailed process flow diagram for the material handling system should be provided for public review and comment.

Further, neither the DRI Application nor the Preliminary Determination Summary contains a top-down BACT analysis for PM₁₀/PM_{2.5} emissions from DRI screening and transport. Rather, they conclude without analysis: "Additionally, hooded conveyors and

enclosed transfer stations will be installed to limit emissions from material handling.” The DRI Application and Preliminary Determination Summary are silent as to BACT for screening. Specific Condition #2 includes a BACT emission limitation for PM10 emissions from DRI-115 and DRI-116, but there is no Specific Condition requiring Nucor to implement any specific control technology for these sources. The Briefing Sheet, on the other hand, identifies a high-energy wet scrubber as the control for DRI-115/116 and the emission calculations identify a “Screening Scrubber,” but nothing is known about how this scrubber was selected or how the assumed PM10/PM2.5 control efficiency was determined. The BACT determination for these sources should be republished with greater clarity.

In addition, the Briefing Sheet does not identify hooded conveyors and enclosed transfer stations as BACT controls for screening and transport (DRI-115/116), but rather only a high-energy wet scrubber. The only DRI scrubber identified on the process flow diagram controls DRI conveying and silos, but there is no mention of screening. Second, the Specific Conditions -- and consequently the Specific Requirements in the Part 70 permit - state a BACT emission limit of 0.002 gr/dscf for PM10. However, the permit record contains no evidence that this limit, which was selected outside of the BACT analysis and is unsupported, in fact represents the maximum degree of reduction that is achievable.

Third, there is no link between the various identified control technologies - scrubber, hooded conveyors, and enclosed transfer stations - and the limit of 0.002 gr/dscf. The uncontrolled PM10 and PM2.5 emissions from each emission source should have been specified as the starting point for the BACT analysis. Absent this, there is no basis for concluding that 0.002 gr/dscf in fact corresponds to the maximum degree of reduction in PM10/PM2.5 from the subject sources. The emission calculations start with a “cleaned gas particulate concentration” (i.e., already controlled) without any explanation of how this level was picked (it should have been selected in the BACT analysis) or relates to the required control technology.

Fourth, the DRI PSD permit -- and consequently the Part 70 permit -- must but does not establish a BACT limit for PM2.5 emissions from these sources.

Fifth, the Specific Conditions in the DRI PSD permit must but do not include a specific condition requiring a target flow rate or pressure drop required to satisfy the BACT emission limitation. The PSD permit must include appropriate monitoring and recordkeeping requirements to assure that BACT emission limits and conditions are met on a continual basis at all levels of operation. NSR Manual, p. B.56. The Part 70 permit includes a specific requirement to determine target flow rates and pressure drops, but this determination would occur after the facility is constructed and operating. This post-construction determination does not satisfy BACT, which is a preconstruction requirement. As the draft permits do not allow for review of the resulting thresholds by the public, this condition violates the public participation requirements of both PSD and Part 70. Moreover, although the Part 70 permit does not disclose the purpose of this indicator monitoring, it presumably is being used as a surrogate for PM10 under the assumption that if emissions are directed to a scrubber and the scrubber is functioning properly, the scrubber will achieve 0.002 gr/dscf and meet the lb/hr and ton/yr emission limitations. However, this has not been demonstrated, and absent a demonstration, no direct testing is not adequate to demonstrate continuous compliance. Therefore, the Specific Conditions in the PSD permit -- and consequently the Specific Requirements in the Part 70 permit -- should require a demonstration that this assumption is valid and further state that exceedances of the indicators are a violation of the underlying BACT

emission limit.

Any such relationship determined from a future study would only be valid for the conditions under which it was developed. If the iron ore composition changed or process operating conditions changed, any such relationship would change. The permits should be revised to require at least annual stack testing to measure particulate emission limitations expressed as gr/dscf, lb/hr and ton/yr to test the validity of the relationship and to directly determine compliance. The study to establish the indicator relationship should be repeated every 5 years or whenever a change occurs that would affect scrubber emissions.

Finally, the BACT PM10 emission limitation for screening and transport (DRI-115/116) is not practically enforceable as it does not include any averaging time. The stringency of an emission limit is a function of both the magnitude and averaging time. Thus, averaging times must be required.

LDEQ Response to Comment No. VII.28

The draft PSD permit PSD-LA-741 is quite clear that sources DRI-115 and DRI-116 require the installation of high-energy wet scrubbers with an efficiency of 90% or greater as control for PM₁₀ and PM_{2.5}, and they are not silent on this matter. It is also quite clear that the one source involves the control of screening operations (DRI-115) while the other involves the control of transfer operations after screening (DRI-116). While these sources may have been grouped in one permit and not the other, the requirements for these sources are consistent across both permits. The emissions calculations for these sources are consistent with other scrubber sources in the permit. The BACT determination for PM_{2.5} is presented in PSD-LA-741, p. 59.

The applicant must demonstrate compliance with both the mass emission limit stated in the permit application, and the percent reduction limitation stated in the draft PSD permit, regardless of the presentation of these emissions. Failure to do so will result in a violation of the permits. Compliance with both of these limitations will be established parametrically through specific monitoring parameters, such as pressure drop, after the results of the initial performance test determine the levels at which such parameters should be monitored.

Hooded conveyors and enclosed transfer stations are required by the PSD permit as BACT for all conveyors and transfer stations at the DRI facility. This requirement is incorporated into the Title V permit by reference. For clarity, LDEQ has included a facility-wide requirement to install hooded conveyors and enclosed transfer stations at the DRI facility as BACT.

Comment No. VII.29

Permit No. PSD-LA-751 does not assure that BACT will be employed for Product Storage Silos (DRI-112/212). The finished DRI product contains both elemental iron and carbon, which can react with oxygen, generating heat and potentially creating fires. Thus, it is stored in silos to isolate it from the weather. A portion of the cooled flue gas from the Reformer, or seal gas, is used to limit the DRI product's contact with the atmosphere, allowing it to slowly oxidize for safer handling and transport. These gases plus particulates from material handling are discharged at the DRI Silo Scrubber.

The gases discharged with the DRI product are seal gas used to pad the silos plus entrained particles from pellet interaction during handling. Seal gas is spent reducing gas. And spent reducing gas is Reformer combustion gases that have not been treated to

remove NO_x. Thus, the BACT determinations for the Storage Silos (DRI-112/212), expressed as a concentration (gr/dscf, lb/MMBtu), should be identical to the Reformer/Main Flue Gas Stack (DRI-108/109) for all pollutants except PM₁₀/PM_{2.5} (due to the pickup of particulate matter from the interaction of pellets) and NO_x (as the seal gas is withdrawn prior to the SCR). Although the Specific Conditions are the same for the Reformer and DRI Storage Silo as to PM₁₀, NO_x and CO, there is no Specific Condition -- and consequently no Specific Requirement in the Part 70 permit -- establishing BACT emission limitations or control technologies for SO₂ and VOC emissions from DRI-112/212. The permits should be revised to include BACT emission limitations and control requirements on SO₂ and VOCs that are identical to those for the Reformer Main Stack.

Second, the BACT emission limitations for NO_x and CO in the Part 70 permit Specific Requirements are expressed as "... lb/MMBtu as adjusted for seal gas system off-take portion from total Reformer flue gas generated by combustion fuel gases." This phrase does not occur in the DRI PSD permit Specific Conditions and standing alone in the Part 70 permit, it makes no sense. It must be defined in the Permits.

Third, the emission calculations indicate that Storage Silos emissions were calculated from an emission factor expressed in lb/MMBtu and the Reformer firing rate, multiplied by the fraction (0.9%) of the total Reformer volumetric vent rate that is diverted for passivating the Storage Silos. This adjustment is applied to the emission rates in lb/hr and ton/yr, not the emission concentration in lb/MMBtu. The use of this factor should be explained in the Specific Requirements and the fraction required as an enforceable condition.

This fraction determines the emission rates in lb/hr and ton/yr (as emissions are calculated by multiplying a lb/MMBtu emission factor by the Reformer firing rate and the off-take fraction) and thus has a direct impact on the modeled ambient concentrations. The NO_x and CO emissions that were modeled in the air quality analysis assume that only 0.9% of the Reformer volumetric vent rate, or 4,000 Nm³/hr, would be vented from the Storage Silos. However, there are no limitations in either the PSD permit nor the Part 70 permit on the amount of seal gas that is vented from the Silos. As this seal gas stream is diverted before the Reformer combustion gases are treated to remove NO_x, this could potentially be a major source of NO_x emissions if more than 0.9% of the untreated gases were diverted to passivate the Storage Silos.

Fourth, the BACT determination for particulate matter emissions is based on the wrong pollutant. The Preliminary Determination Summary concludes that BACT for the Storage Silos is a high energy scrubber achieving at least 99% control of PM₁₀/PM_{2.5}. Specific Condition #2 establishes the PM₁₀ BACT emission limitation as 0.002 gr/dscf, which is equivalent to 0.003 lb/MMBtu. The Part 70 permit; on the other hand, establishes the PM₁₀ BACT emission limitation as 0.010 lb/MMBtu, based on filterable plus condensable. The regulated pollutant is total PM₁₀, comprising the sum of filterable plus particulate PM₁₀. It is unclear whether the PSD limitation, 0.002 gr/dscf, is filterable PM₁₀ or total PM₁₀. The metric "gr/dscf" is generally only used for filterable PM₁₀. Thus, the proposed limit of 0.002 gr/dscf (0.003 lb/MMBtu) is likely only the filterable portion of particulate matter. The emission calculations indicate that the Storage Silos will emit both filterable PM₁₀ (0.004 lb/MMBtu) and condensable PM₁₀ (0.006 lb/MMBtu). In fact, the major portion of particulate matter is condensable. The BACT determinations do not appear to include a top-down analysis for the condensable fraction and the draft PSD Permit does not appear to contain any BACT emission limitations for

the condensable fraction. The controls for condensable particulate matter, for example, are distinct from filterable controls, including, for example, sorbent injection and wet electrostatic precipitation. The condensable fraction of PM10/PM2.5 are components of a PSD regulated pollutant, which is an applicable requirement that must be included in the PSD permit and Part 70 permit.

Fifth, the Step 3 ranking is defective as it reports only the percent PM10 removed, excluding the expected emission rate (e.g., lb/hr, lb/MMBtu) and the expected emission reduction. Hence, there is no link between the evaluated control technologies and the limit of 0.002 gr/dscf. The permit record contains no evidence that this limit, which was selected outside of the BACT analysis and is unsupported, represents the reported 99% control efficiency nor the maximum degree of reduction that is achievable. Instead, the emission calculations are based on different concentrations.

The uncontrolled PM10 and PM2.5 emissions from furnace dedusting should have been specified as the starting point for the BACT analysis. Absent this, there is no basis for concluding that 0.002 gr/dscf in fact corresponds to the maximum degree of reduction in PM10/PM2.5 from the subject sources. For example, if the uncontrolled PM10 emission concentration were 0.2 gr/dscf, the proposed limit of 0.002 gr/dscf would correspond to 99%. However, if the uncontrolled PM10 emission concentration were only half that, 0.1 gr/dscf, the proposed limit would correspond to only 80% control. The emission calculations start with a “cleaned gas particulate concentration” (i.e., already controlled) without any explanation of how this level was picked (it should have been selected in the BACT analysis) or relates to the required control technology.

Sixth, the Specific Conditions in the DRI PSD permit -- and consequently the Specific Requirements in the Part 70 permit -- do not require that Nucor install the BACT control technology, but rather, only places limits on its operation in the form of an untested concentration, an unspecified scrubber flow rate (0.00 gal/min) or pressure drop range, and lb/hr and ton/yr emission rates, which are not routinely monitored and have no computational or engineering link to the technology itself. The Specific Conditions - and consequently the Specific Requirements -- should be modified to require the installation of a 99% efficient scrubber.

Seventh, the permits must but do not establish a separate BACT determination and emissions limit for PM2.5.

Last, the Specific Conditions in the DRI PSD permit must but do not include a specific condition requiring a target flow rate or pressure drop required to satisfy the BACT emission limitation, and conditions necessary to assure compliance. The PSD permit must include appropriate monitoring and recordkeeping requirements to assure that BACT emission limits and conditions are met on a continual basis at all levels of operation. NSR Manual, p. B.56. The Part 70 permit allows setting a scrubber flow rate or pressure drop range to assure compliance with the PSD limitation but fails to identify which limitation is the target (Specific Requirements #110, #266). One must guess that it is PM10 and speculate as to whether it covers just gr/dscf or also the lb/hr and ton/yr limits. The flow rate and pressure drop allowable ranges would be determined after the facility is built, under an administrative permit amendment. No public review is required for an administrative amendment. As the scrubber flow rate/pressure drop is likely a surrogate to determine continuous compliance with a BACT emission limit, it must be subject to public review. These post-construction studies do not satisfy BACT, which is a preconstruction requirement and thus violate the public participation requirements of both PSD and Part 70.

The Part 70 permit does not disclose the purpose of this flow rate/pressure drop monitoring, but presumably, it is being used as a surrogate for PM10 under the assumption that if emissions are directed to a scrubber and the scrubber is functioning properly, the scrubber will achieve 99% PM10 removal and meet the gr/dscf and lb/hr emission limitations. Therefore, the Specific Conditions in the PSD permit -- and consequently the Specific Requirements in the Part 70 permit -- should state that exceedances of these future thresholds would be a violation of the underlying BACT emission limit.

Flow monitoring reveals no information about PM10 concentrations expressed in gr/dscf nor lb/MMBtu or PM10 emission rates expressed in lb/hr and ton/yr, unless studies are conducted to establish a statistically valid relationship between flow rate and these emission metrics. Thus, the Specific Conditions -- and Specific Requirements #110 and #266 -- should require a study to demonstrate a relationship between the flow/pressure and the subject applicable requirements. Otherwise, the proffered BACT PM10 limit is not enforceable as a practical matter and the permits do not assure compliance with BACT.

Any such relationship would only be valid for the conditions under which it was developed. If the iron ore composition changed or process operating conditions changed, any such relationship would change. The permits should be revised to require at least annual stack testing to measure particulate emission limitations expressed as gr/dscf, lb/MMBtu, lb/hr and ton/yr to test the validity of the relationship and to directly determine compliance. The study to establish the indicator relationship should be repeated every 5 years or whenever a change occurs that would affect scrubber emissions.

LDEQ Response to Comment No. VII.29

This comment is materially the same as Comment No. VII.24. See LDEQ Response to Comment No. VII.24 for our response to Comment No. VII.29.

Comment No. VII.30

Permit No. PSD-LA-751 does not assure that BACT will be employed for the Acid Gas Absorption Vents (DRI-111/211). Acid gases present in the top gas from the Shaft Furnace are concentrated in an amine-based absorption scrubber, the captured acid gases released in a steam reboiler, treated to remove sulfur and vented to atmosphere. The BACT analyses for the Acid Gas Absorption Vents have the same general deficiencies as previously described for the Upper Seal Gas Vents. The top-down analysis only identified control technologies, rather than emission limits, the draft Title V Permit Specific Requirements do not include the Acid Gas Absorption Vent, and the draft PSD Permit emission limits are expressed as tons-per-year emission rates for PM10, PM2.5, SO2, and CO. These represent deficiencies for the reasons explained in the comments below. There are further deficiencies with the BACT determinations for the Acid Gas Absorption Vent, as described below.

Neither Nucor nor the LDEQ made a BACT determination for NOx or VOC emissions from the Acid Gas Absorption Vents. The presumption is that the emissions are *de minimis*. This should be clarified and documented in the record.

The Preliminary Determination for CO concludes that, due to the low emissions, no

technologies exist that could meet the environmental, energy, and economic criteria inherent in a BACT review. However, the emission calculations which support the air quality modeling suggest that “catalytic oxidation” was assumed in calculating CO emissions. Catalytic oxidation is a control technology that is used to reduce CO emissions. Thus, the PSD permit -- and consequently the Part 70 permit -- must be revised to either require catalytic oxidation or revise emission calculations and air quality modeling.

LDEQ Response to Comment No. VII.30

The commenter is in error, there is no assumption that emissions of NO_x or VOC from the Acid Gas Absorption Vents are *de minimis*. Emissions of these criteria pollutants were not presented by the applicant as reasonably being expected to exist, and LDEQ has agreed with this analysis based on our understanding of the DRI process. The spent reducing gas treated by the acid gas absorber is generated as part of the reduction furnace process, and VOC compounds are not a fundamental component of this process. Additionally, VOC's from industrial sources are generally not acidic in nature, and would not be expected to be separated from the spent reducing gas fuel by an acid gas absorber. Minor VOC concentrations in the spent reducing gas, should they even exist, would be introduced as fuel into the flame zone of the reformer. In this sense, LDEQ feels that a conservative approach to the control of VOC compounds has been taken, whether or not such compounds will exist, or if that was the intent of the applicant when selecting a process design.

Similarly, the applicant has often indicated that the presence of nitrogen in the reduction furnace is undesirable, and the process is designed to maintain a nitrogen deficient atmosphere within the furnace. Should they exist, NO_x compounds could theoretically be separated by the acid gas absorber and then vented to the atmosphere through the acid gas absorption vents. However, LDEQ has agreed with the characterization of the gas emitted from the acid gas absorption vents, and we believe that emissions of NO_x compounds will not occur from this source.

Research into the SulfaTreat catalyst selected as BACT for control of SO₂ emissions through the capture and oxidation of H₂S into elemental sulfur and iron pyrite, determined that this catalyst will also catalyze carbon monoxide to some degree. This conclusion was confirmed by the applicant as the reason for the nomenclature contained in the emission calculations. The emission factor for CO was provided by the vendor. Due to the low absorption rate of CO by the acid gas absorber, and the fact that the existing control for SO₂ exerts some control of carbon monoxide as well, LDEQ has exercised its discretion in determining that stand-alone controls for such a minor quantity of CO emissions could not possibly be economically feasible, and did not require additional information in regard to this BACT analysis.

Comment No. VII.31

Permit No. PSD-LA-751 does not assure that BACT will be employed for the Hot Gas Flares (DRI-110/210). As explained supra, the Shaft Furnace is sealed by the seal gas system, where the seal gas is spent reducing gas cleaned by the wet scrubbers. The pressure of the reducing gas within the Furnace must be maintained below the pressure of the seal gas system or an uncontrolled release of reducing gas will occur. When pressure surges occur in the reducing gas recycle system, uncontrolled releases of reducing gas results. These releases are routed to the Hot Flare for combustion. The following sections first discuss generally issues with the Hot Gas Flare BACT determinations, followed by a discussion of issues related to specific pollutants.

The process flow diagram indicates that at least two other gas streams besides spent

reducing gases from the Shaft Furnace are routed to the Hot Gas Flare: (1) blowdown from QCW/ECW users and (2) lowdown from solids removal. The emission calculations, on the other hand, characterize the gases released to the flare as “top gas.” The emission calculations did not include any emissions from venting these two additional streams.

Further, flares generally handle routine releases (*e.g.*, the venting of spent reducing gas due to pressure surges) as well as startups, shutdowns, and malfunctions. The Specific Requirements, for example, contemplate “an emergency” that could exceed 6 hours. The permit record does not explain how startup, shutdown, and emergency releases will be handled, but it is a fair guess that they would be routed to the Hot Gas Flare, or another facility flare. The permit record does not include any emission calculations or BACT analyses for these releases, which are typically much larger than routine releases and which must be included in the BACT determination and emission inventory. The source impact analyses, for example, should have been based on maximum potential releases from the Flare, during a design basis event, such as a power outage.

In addition, the BACT analyses, supporting emission calculations, and air quality analyses all make assumptions about the composition, flow rate, and duration of releases to the Hot Gas Flare and resulting byproducts of combustion. These critical assumptions include hours of operation per year (8,000), the amount of gas sent to the Flare (1,000 average; 2000 maximum Nm^3/hr), and the criteria pollutant emission factors. None of these assumptions are imposed as operating limits in the permits. Thus, Nucor could emit substantially more pollution at the Flare than included in its emission calculations. For example, the emission calculations for the maximum hour assume that only 2,000 Nm^3/hr (70,700 SCF /hr or 18 MMBtu/hr) of spent reducing gas would be combusted in the Flare. However, without any limit in its operating Permit, Nucor could vent substantially more, up to the design basis of the Flare (which is not disclosed). Thus, the permits should be modified to limit the use of the Flare to those assumptions included in the emission calculations or 8,000 hr/yr and 2,000 Nm^3/hr .

LDEQ Response to Comment No. VII.31

The commenter states that emissions from the Hot Gas Flare should be calculated based on a design malfunction. While LDEQ agrees that SSM events may need to be considered in permitting, it is not appropriate to base potential to emit or related calculations on malfunction events. In the *Louisiana Pacific* case, commenters urged that potential to emit and permit conditions should be based upon malfunction conditions. This contention was rejected by the U.S. District Court. LDEQ similarly declines to rely upon malfunction conditions for establishment of general flare operating conditions.

The commenter asserts that operation of the Hot Gas Flare, which is used for both process and upset conditions, should be limited. LDEQ disagrees. The flare is permitted for potential to emit operation from normal process operations and there is no reasonable expectation that regular emissions would exceed that presented in the application and calculations. LDEQ is not required to impose conditions to prevent occurrences that are not reasonably anticipated to occur. Similarly, LDEQ declines to impose limits on the use of the flare that might preclude its use in appropriate emergencies.

Emissions from various sections of the facility will be controlled by the flares. Emissions from the flares are limited by the rates listed in the Title V permit and the PSD permit. Emissions above these limits are considered violations of the permits and must be reported.

Operating times, flare gas flow rates, and heat input are not assumptions. They are design bases for the flares. The flares are permitted to operate 8,000 hour/year, or eleven months a year. Utilizing the flares to control emissions is a positive environmental method. The permit should not limit the operating time of the flares.

Comment No. VII.32

The BACT determination for PM10/PM2.5 emissions from DRI-110/210 is missing and must be provided. The permit record does not appear to contain a responsive top- down BACT analysis for PM10 emissions from the Hot Gas Flare. The draft permits and supporting permit file are unclear on BACT for PM10 emissions from the Hot Flare. The BACT analysis in the DRI Application concludes “the best available technology for controlling PM10 from the hot flare is treatment of the reducing gas by a high-energy scrubber.” The Briefing Sheet reports PM10 BACT as flue gas cleaning by wet scrubbing of the spent gas stream prior to its use as fuel in the combustion chamber. The Preliminary Determination Summary does not contain a BACT analysis for the Hot Gas Flare, instead arguing that “Particulate matter cleaning of the spent reducing gas has already been addressed, so BACT for PM is venting to the Flare after the spent reducing gas has been cleaned by the wet scrubbers described as BACT for the Reformer Flue gas.” Finally, the draft PSD Specific Conditions and draft Part 70 Specific Requirements do not report any BACT emissions limitations or determinations for the Hot Gas Flare.

These sources appear to be arguing that treatment of the reducing gas before it is introduced into the Shaft Furnace satisfies PM10 BACT for combustion of reducing gases vented to Hot Gas Flare to relieve pressure. However, this ignores the particulate pickup in the Shaft Furnace. The process flow diagram (excerpted in Figure 2 below) indicates that the spent reducing gas vented to Hot Gas Flare (see dashed line) exits the Shaft Furnace (Reactor), bypasses the wet gas scrubber (Reducing Gas Cooling & Cleaning), and is sent untreated directly to the Flare. While this gas would have been treated before it entered the Furnace, the spent recycle gas removed from the Furnace would have picked up particulate matter from the action of pellets passing through the Furnace. The fact that the Flare is called the “Hot” Gas Flare suggests that hot gases are vented to the Flare, before the cooling and scrubbing occur.

Further, the PM10 emission calculations for the Hot Gas Flare are based on an emission factor of 0.0075 lb/MMBtu. This is equivalent to 0.46 gr/dscf. All of the other sources that vent spent recycle gas (see Comment II.B.8: DRI-107/207, DRI-112/212, DRI-115/116) have a PM10 BACT limitation of 0.002 gr/dscf, a factor of 230 times lower. This supports the position that the gases vented at the Hot Gas Flare have not been treated by the recycle gas scrubber. This (0.46 gr/dscf) is a very high concentration and does not represent the maximum degree of reduction that is feasible, as evidenced by the PM10 concentration reported for other sources that vent a similar gas. This stream should be treated with a high velocity wet gas scrubber.

LDEQ Response to Comment No. VII.32

The comment is factually incorrect; a BACT analysis was performed for emissions of PM₁₀ and PM_{2.5} from the Hot Gas Flare. LDEQ agreed with the permit applicant that post-combustion control options for particulate from the flare do not exist. Contrary to the commenter’s depiction of the process configuration, the wet scrubber which serves to clean the spent reducing gas is placed downstream of the reduction furnace, and not prior to it. The “hot” nomenclature signifies that the flare combusts the gases upon venting, as opposed to “cold” flares which simply vent the spent

reducing gas, which are actually prevalent in the industry.

Spent reducing gas overpressure events from the Shaft Furnace are not quantifiable or predictable. So, they cannot be reused and must be routed to the flares. Designing a treatment system for this gas stream is not practical.

Comment No. VII.33

The BACT determinations for SO₂, NO_x and CO emissions from DRI-110/210 emissions from DRI-110/DRI-210 are flawed. The Preliminary Determination Summary concluded that there is no feasible control for SO₂ emissions from the Hot Gas Flare, but the Specific Conditions indicate BACT is the combustion of natural gas containing no more than 2,000 gr/MMscf. The draft Title V Specific Requirements fail to incorporate this PSD Specific Condition. Further, the Part 70 permit Specific Requirements do not require any monitoring of the sulfur content of the natural gas. Thus, there should be, but is, no enforceable limit on SO₂ emissions from the Hot Gas Flare.

The DRI Application and the Preliminary Determination Summary both conclude that BACT for NO_x emissions from the Hot Gas Flare is the inherent low-NO_x combustion properties of reducing gas. However, neither the PSD Specific Conditions nor the Part 70 Specific Requirements limit the Flare to low-NO_x reducing gases, nor do they include any operational limits to assure that this restriction is achieved. The Specific Conditions - - and consequently the Specific Requirements -- should be revised to reflect BACT for NO_x emissions.

The DRI Application and the Preliminary Determination Summary both conclude that BACT for CO and VOCs (the Preliminary Determination Summary omitted VOCs from its BACT determination) is good combustion practices, assumed to remove 50% of the emissions. The PSD Specific Conditions specify only “good combustion practices” without noting the assumed 50% while the Part 70 Specific Requirements contain no BACT limitations for CO or VOC nor any monitoring or recordkeeping to assure good combustion practices are achieved. This does not satisfy BACT.

The spent reducing gas that will be vented contains very high concentrations of CO. Flares can be designed to destroy 98% of this CO. However, without a specific requirement to do so, and in fact, a determination that BACT is only 50%, there would be no incentive to do so. The BACT analysis is flawed as it failed to identify 98% CO reduction as a feasible control option. The DRI PSD permit should be revised to include a Specific Condition requiring that the Flare be designed to remove 98% of the CO. Any VOCs present would be reduced by a comparable amount.

LDEQ Response to Comment No. VII.33

Natural gas is combusted at the flare as pilot flame gas. The combustion of natural gas containing no more than 2,000 gr/MMscf of sulfur for this purpose is required. In order to certify compliance with this requirement, the facility must retain evidence that natural gas supplied to the facility meets this requirement. Periodic natural gas analysis reports, usually provided by the supplier monthly, are firm evidence in support of compliance with this requirement.

LDEQ agreed with the permit applicant that post-combustion control options for NO_x from the flare do not exist. The Hot Gas Flare is to be installed for the purpose of controlling potential venting of spent reducing gas. The spent reducing gas is itself the low-NO_x fuel specified as BACT for this

source. Assertions by the commenter that Nucor may decide to combust other gases at a flare are made without support.

LDEQ agrees with the commenter that a flare can achieve an overall control efficiency of at least 98% for carbon monoxide. A review of the calculations presented by the applicant indicates that the flare will achieve at least this level of control. The permits have been updated to reflect the requirement that the permittee shall install a flare designed to achieve a minimum of 98% control of carbon monoxide.

Comment No. VII.34

Permit No. PSD-LA-751 must -- but does not -- include a BACT determination and air quality impact analysis for particulate matter (PM₁₀ and PM_{2.5}) that is emitted from paved and unpaved roads (FUG-101 and FUG-102) as a result of the increased use associated with DRI manufacturing. FUG-101 and FUG-102 are permitted in the pig iron PSD permit and initial Part 70 permit. FUG-102, the emissions from paved roads, was transferred from the initial pig iron Part 70 permit to the DRI Part 70 permit, while FUG-101, the emissions from unpaved roads, was carried over into the modified pig iron Part 70 permit (albeit, as discussed below, in an unlawfully modified form). The emission calculations for transferred FUG-102 indicate that Nucor expects the number of miles traveled over paved roads to decrease from 200 mi/day if the facility includes only the pig iron process to 100 miles/day if the facility includes the pig iron process and the DRI process (the Inventories table in the DRI Part 70 permit, however, reflects that traffic on paved roads will average 43,800 vehicle miles per year, the same amount reflected in the Inventories table in the initial pig iron Part 70 permit).

It is not entirely clear which roads in the facility will be paved or unpaved, or whether paved roads will be located solely within the battery limits of the DRI process and unpaved roads solely within the battery limits of the pig iron process. Three things, however, are clear. First, traffic associated with the DRI process will necessarily travel over roads located in the pig iron process battery limits because the DRI process will be land-locked. *See* EDMS Doc. 6952414, p. 22. If only unpaved roads are located inside the pig iron battery limits, as suggested by the modified pig iron Part 70 permit, this means traffic associated with the DRI process will cause increased emissions from unpaved roads in the pig iron plant. Alternatively, if some roads in the pig iron process battery limits will be paved, the DRI process will cause increased emissions from those roads. Second, the increase in overall production at the aggregate pig iron-DRI facility will increase the overall traffic on paved and unpaved roads. The aggregate facility will import the same amount of coal and lime to produce the same amount of coke, coke breeze, FGD dust and slag, and will import 33% more iron ore and produce 33% more iron feedstock for Nucor's steel mills. Moreover, the iron product will be in three forms - pig iron, DRI pellets and DRI briquettes -- which cannot be stored together. Indeed, all other things equal, increasing the number of type of iron produced at the facility will cause an increase in traffic over paved and unpaved roads. Coupled with the increase in annual production, there certainly will be an increase in traffic. The increase in overall traffic and the shift of traffic from paved roads to unpaved roads (which have a much higher emission rate than paved roads) will cause combined emissions from paved and unpaved roads to increase. As explained more fully in the comments below, this increase in emissions will be significant. Third, there almost certainly will be areas inside the pig iron process battery limits (for example, access roads to offices, control rooms, and parking lots) where it will be practicable to pave the roads.

Specific Condition No. 11 in the pig iron PSD permit establishes BACT for paved and unpaved roads as:

BACT for road dust is to *pave roadways where practicable including areas where the extra heavy vehicles (greater than 50 tons in weight) will not cause damage to paving*. Watering and sweeping will be used on paved roads along with reduced speed limits of less than or equal to 15 mph. Unpaved roads shall utilize water spray or dust suppression chemicals to reduce emissions. Additionally, reduced speed limits of less than or equal to 15 mph will be enforced on all unpaved roadways.

See EDMS Doc. 47485697, pp. 120-22 (emphasis added). The requirement to “pave roadways where practicable” does not appear in the DRI Part 70 permit or the modified pig iron Part 70 permit.

These changes proposed by the DRI Part 70 permit and modified pig iron Part 70 permit violate PSD in four ways. First, BACT requirements - including the requirement to “pave roadways where practicable” -- exist independent of a Part 70 permit and cannot be eliminated or modified except through the BACT process under PSD. Otherwise, for example, if Nucor decides not to construct the DRI process, there would be no legal mechanism to require Nucor to pave any roads -- indeed, all the roads at the facility could be unpaved. The DRI Part 70 permit and modified pig iron Part 70 permit must incorporate the original BACT requirement to pave roads, unless, as described below, a new or modified BACT determination for roads is included in the DRI PSD permit.

Second, construction of roads in the DRI process battery limits and use of roads in the pig iron process battery limits for DRI-related traffic constitute a physical change and change in the method of operation of sources FUG-101 and FUG-102. See LAC 33:III.509.A (definition of “major modification”). The changes in the roads are not simply changes in the “hours of operation or in the production rate” because the aggregate production rate of the facility is increasing 33% above the rate authorized in the pig iron PSD permit, and construction of the DRI process will cause roads to be constructed in different locations than would be the case if the DRI process is not constructed. Because the roads will be modified, the DRI PSD permit should have included a BACT analysis for paved and unpaved roads in the aggregate facility. This analysis may or may not have resulted in a different BACT determination than is made in the pig iron PSD permit; but, a BACT determination for roads in the DRI PSD permit would have been incorporated into the DRI Part 70 permit (it could also have been incorporated in the modified pig iron Part 70 permit since, unlike PSD, Part 70 does not prohibit an aggregate facility from being permitted under multiple permits).

Third, the conflation of the paved road source in the DRI Part 70 permit and the unpaved road source in the modified pig iron Part 70 permit reinforces the requirement that the DRI and pig iron projects be permitted under a single, aggregate, PSD permit, both for BACT and air quality impact analysis purposes. As described in Zen-Noh's comments regarding the pig iron PSD permit, see EDMS Doc. 47485821, and the comments below, emissions from unpaved roads will be a major contributor to air pollution at Zen-Noh. Construction of the DRI process will not lessen or improve the impacts at Zen-Noh because the DRI process will be located even closer to Zen-Noh than the pig iron process (and much closer than Blast Furnace #2 and its associated emissions sources). The DRI permit must -- but does not -- include an ambient air quality analysis that accounts for PM₁₀ impacts from paved and unpaved roads at the aggregate facility.

Fourth, the surreptitious removal of the BACT requirement to pave roads where practical and failure to provide BACT and ambient air quality impact analyses for PM₁₀ and PM_{2.5} emissions from the paved and unpaved roads at the aggregate DRI-pig iron facility violates the public participation requirements in PSD. The DRI PSD permit should be modified to include these necessary analyses and reissued for public comment.

LDEQ Response to Comment No. VII.34

The commenter does not support the contention that the DRI facility will require an increase in the amount of road traffic proportional to the quantity of DRI produced. Unlike the pig iron facility, the DRI facility has been presented as requiring very little heavy-duty truck traffic. Raw material iron ore pellets will be transported by conveyor, and stacked and reclaimed by rail-mounted machines. Product DRI will be stored in silos, and also transported by conveyor. This is in contrast to the concept of moving pig iron to the docks with heavy-duty trucks, because the pigs cannot be transported by conveyor. Even water trucks used to control emissions of dusts from road traffic will be reduced by the installation of automatic sprinkler systems.

The applicant did not present a change in the number and type of heavy-duty road traffic to be expected on plant roads with the DRI permit application or the pig iron permit modification. LDEQ has not specified or dictated the precise location of plant roads, and does not believe that is the intent of PSD when addressing emissions from fugitive sources. Similarly, LDEQ does not specify the precise locations of valves in a refinery. We do not believe that a change in the method of operation has occurred, because 1) no baseline of operation exists for which a comparison may be made, 2) the applicant has not requested a change in the use or operation of the source in question, and 3) site maps provided with the application have shown that the number and location of roads within the two facilities have not significantly changed.

The commenter contends that LDEQ has failed to provide a proper BACT analysis for the source FUG-102 “Paved Roads” because a specific requirement was not included that requires the paving of roads where applicable. This source only represents the roads that are required to be paved, not all roads the property. The commenter also contends that LDEQ has failed to provide a proper air quality analysis because emissions of PM₁₀ and PM_{2.5} from paved roads and unpaved roads were not aggregated in a single PSD permit. However, combined emissions from these sources underwent an air quality analysis as part of the review of PSD-LA-751, which required refined modeling for PM₁₀ and PM_{2.5}.

The operator will be responsible for certifying compliance with the emission limitations contained within the Title V permit, based on credible evidence developed through reasonable inquiry, including emissions of fugitive dust from plant roads.

Comment No. VII.35

Permit No. PSD-LA-751 must -- but does not -- include a BACT determination for particulate matter (PM₁₀ and PM_{2.5}) that is emitted from the loading/unloading gantry cranes (DOC-101) as a result of the increased throughput associated with DRI manufacturing. This source was transferred from the initial pig iron Part 70 permit to the DRI Part 70 permit but is not addressed in the DRI PSD permit. The gantry cranes variously load or unload iron ore, coal, flux, pig iron, DRI, slag, and coke fines. The iron ore is used at both the pig iron and DRI Plants. The amount of iron ore unloaded at DOC-101 increased from 4,500,000 tonne/yr in the initial pig iron Part 70 permit to 5,750,000 tonne/yr in the DRI Part 70 permit, or by 1,250,000 tonne/yr. This is consistent with

eliminating one pig iron train (3,000,000 tonne/yr) and adding two DRI trains (5,000,000 tonne/yr). And, to the extent that DRI is transported by ship rather than barge, DOC-101 will be used to load DRI onto ships. Thus, DOC-101 is a shared or common facility that unloads iron are to be processed by both the pig iron and DRI processes and loads the iron product from both processes. Therefore, this change in throughput is part of the DRI project. A BACT determination for the modifications to DOC-101 must be provided in a PSD permit and emissions from DOC-101 must be included in the air quality impact analysis -- both either in the DRI PSD permit or, preferably, a PSD permit for the aggregate DRI/pig iron facility.

LDEQ Response to Comment No. VII.35

The BACT requirement for the source DOC-101 is clearly listed in the Title V permit, as well as the emission rate limitation for this source. LDEQ did not find reason to change the BACT analysis for this source due solely to its transfer from one permit to the other. The commenter's contention that DRI will be loaded onto ships is in error; the applicant has publically stated repeatedly that the facilities' products will be shipped by barge to Nucor's existing facilities, and emission calculations establishing emission rate limits reflect that assumption throughout. Emissions from the dock were included in air quality impact analysis for particulate matter. The requested transfer of this source from the pig iron permit to the DRI permit was completed for the Title V permit, but not for the PSD permit. LDEQ has rectified this omission in the final PSD permit.

Comment No. VII.36

Permit No. PSD-LA-751 must -- but does not -- include a BACT determination for particulate matter (PM₁₀ and PM_{2.5}) that is emitted from the conveyors (FUG-103) as a result of the increased throughput associated with DRI manufacturing. This source was transferred from the initial pig iron Part 70 permit to the DRI Part 70 permit but is not addressed in the DRI PSD permit. The conveyors transport material between the loading docks and the DRI and pig iron processes. These materials include coal, iron ore, flux, and mill scale. Fugitive PM₁₀/PM_{2.5} emissions are released at various drop points. The initial pig iron Part 70 permit is based on conveying 9,000,000 tonne/yr of iron are while the emission rate listed in the DRI Part 70 permit is based on conveying 11,500,000 tonne/yr of iron are. This is consistent with eliminating one pig iron train (3,000,000 tonne/yr) and adding two DRI trains (5,000,000 tonne/yr). In addition, the DRI process will include new or different conveyors than are permitted under the pig iron PSD permit -- including, at least, conveyors to transfer DRI product to the DRI storage bins and, from there, to the barge and ship loading docks, and DRI furnace feed conveyors. None of these new conveyors is subject to the BACT determination for FUG-103 in the pig iron PSD permit, and must be subjected to a new BACT determination. These conveyors, of course, will handle only DRI. Other conveyors at the facility will handle pig iron and other materials associated only with pig iron production, e.g., flux. Unlike the DRI-specific conveyors and the conveyors that will transport materials common to both processes, the pig iron-specific conveyors likely are still permitted under the pig iron PSD permit. Nonetheless, the combined source FUG-103 is a shared or common source. The new conveyors and change in throughput for "existing" conveyors associated with DRI production must be incorporated into a PSD permit, including a BACT determination and air quality impact analyses. This could be in the DRI PSD permit or, preferably, a new PSD permit for the aggregate DRI-pig iron facility. The DRI PSD permit does not contain a PSD analysis for FUG-103.

Further, even though the iron ore throughput increases, the resulting maximum hourly

PM10 emission rate for these two cases in the emission inventory and emission calculations decrease from 3.17 lb/hr in the final Pig Iron Permit to only 1.90 lb/hr in the draft DRI Permit. The emission rate used in the modeling, on the other hand, did not change. The value used in both the initial pig iron Part 70 permit and the DRI Part 70 permit 10112/10 modeling is 3.17 lb/hr, spread out among five sources, presumably five drop points.

Our investigations indicate that this decrease is due to reducing the number of drop points from five to three in the emission calculations. The permit record contains no support for this change. Drop points are locations where the conveyors empty into storage areas. This change apparently was not modeled, as the draft PSD permit modeling (10/12110) uses 3.17 lb/hr spread among six drop points. As more iron ore will be handled under the DRI scenario, maximum hourly emissions from the storage area, FUG-103, which receives the increase in iron ore, should increase. However, they do not. Further, the number of drop points for the conveyors (5) should match the number of volume sources used to model the piles (6) as the conveyors empty into storage areas. They do not. We were unable to resolve these discrepancies or opine on their effects on the modeling as neither the pig iron nor the DRI application contain a material handling process flow diagram, a fundamental flaw. *See, e.g., R. Bohn et al., Fugitive Emissions from Integrated Iron and Steel Plants*, March 1978, Figure 2-4 (this report was relied on by Nucor for estimating wind erosion emissions from storage piles). Further, there are evident errors in the emission calculations, e.g., summary tables do not agree with the sum of the parts.

LDEQ Response to Comment No. VII.36

The BACT requirement for the source FUG-103 is clearly listed in the Title V permit, as well as the emission rate limitation for this source. Although emissions from this source increased incrementally, LDEQ did not find reason to change the BACT analysis for this source due to its transfer from one permit to the other. The commenter's contention that conveyors within the DRI facility are not included in the DRI facility permits is in error; conveyor drop points and screening stations are permitted individually and separately from the conveyors bringing in raw material from the dock. Emissions from source FUG-103 were included in air quality impact analysis for particulate matter. Maximum hourly emissions from this source do not increase because the conveyors were presented with a design maximum conveyance rate, which was not changed with transfer of this source to the DRI facility. The requested transfer of this source from the pig iron permit to the DRI permit was completed for the Title V permit, but not for the PSD permit. LDEQ has rectified this omission in the final PSD permit.

Comment No. VII. 37

Permit No. PSD-LA-751 must -- but does not -- include a BACT determination for particulate matter (PM₁₀ and PM_{2.5}) that is emitted from the iron ore storage piles (PIL-102) as a result of the increased throughput associated with DRI manufacturing. This source was transferred from the initial pig iron Part 70 permit to the DRI Part 70 permit but is not addressed in the DRI PSD permit. Iron ore pellets, the primary raw material for both plants, is stored in outdoor piles, designated as source PIL-102. This source was modeled as six separate volume sources, presumably six separate storage piles. Emissions are generated by three activities: (1) material transfer into and out of the pile (stacking and reclaiming); (2) equipment traffic in the storage area; and (3) wind erosion of the storage piles.

The allowable emission rates for PIL-102 in the initial pig iron Part 70 permit are based

on conveying 9,000,000 tonne/yr of iron ore, while the allowable emission rates in the DRI Part 70 permit are based on conveying 11,500,000 tonne/yr of iron ore. This is consistent with eliminating one pig iron train (3,000,000 tonne/yr) and adding two DRI trains (5,000,000 tonne/yr). Thus, PIL-102 is a shared or common facility that supplies iron ore required by both the pig iron and DRI processes. Therefore, this change in throughput is part of the DRI project and should be incorporated into the DRI PSD permit, including the DRI BACT and air quality impact analyses -- or, preferably, into a new PSD permit for the aggregate DRI-pig iron facility. The DRI PSD permit does not contain a BACT analysis for PIL-102.

LDEQ Response to Comment No. VII.37

The BACT requirement for the source PIL-102 is clearly listed in the Title V permit, as well as the emission rate limitation for this source. Although emissions from this source increased incrementally, LDEQ did not find reason to change the BACT analysis for this source due to its transfer from one permit to the other. Emissions from source PIL-102 were included in air quality impact analysis for particulate matter. The requested transfer of this source from the pig iron permit to the DRI permit was completed for the Title V permit, but not for the PSD permit. LDEQ has rectified this omission in the final PSD permit.

Comment No. VII.38

Permit No. PSD-LA-751 must -- but does not -- include a BACT determination for sulfuric acid mist ("SAM") emissions from DRI sources equipped with SCR control technology. PSD review is required if the potential to emit any regulated pollutant equals or exceeds significance thresholds. The significance threshold for sulfuric acid mist is 7 ton/yr. Thus, if the DRI facility emits 7 ton/yr or more sulfuric acid mist, Nucor must prepare a BACT analysis for SAM. LAC 33:III.509. The permit record is silent on sulfuric acid mist.

The DRI project will add SCR to control NO_x at four units: (1) two package boilers (DRI-109/209) and (2) two reformer furnaces (DRI-108/208). An SCR converts some of the SO₂ in the exhaust gases to sulfur trioxide (SO₃). The sulfur trioxide combines with water in the combustion gases and is converted into very small liquid droplets of sulfuric acid (H₂SO₄), called sulfuric acid mist or SAM, before it leaves the stack. A standard SCR catalyst converts 3% of the SO₂ to SO₃. The DRI Application and Preliminary Determination summary did not consider this byproduct of SCR use. These emissions are estimated below, after correcting the errors in the SO₂ emissions.

The SO₂ emissions from the package boilers were calculated using a natural gas sulfur content 87.3 times lower than the BACT determination, which was set at the lower end of the range of sulfur in natural gas, 2,000 gr/MMscf. Assuming natural gas containing 2,000 gr/MMscf, SO₂ emissions from the two boilers would increase from 0.66 ton/yr to 15.1 ton/yr.

The SO₂ emissions from the reformers were calculated assuming 95% of the sulfur in spent reforming gas (top gas) would be removed using acid gas scrubbing. However, neither the draft PSD permit nor the draft Title V Permit requires the use of acid gas scrubbing. The permits also do not require any routine monitoring for SO₂ at the Reformer vent. Thus, there is nothing to prevent Nucor from not scrubbing the top gas. Assuming the top gas is not scrubbed, SO₂ emissions from the two reformers would increase from 23 ton/yr to 460 ton/yr.

A conventional SCR catalyst converts about 3% of the SO₂ in the combustion exhaust gases to sulfuric acid mist. Thus, the SCR proposed for the package boilers and reformers would emit 22 ton/yr of sulfuric acid mist. Thus, sulfuric acid mist emissions exceed the 7 ton/yr significance threshold, triggering PSD review.

A BACT analysis is required and should consider control options such as sorbent injection, wet electrostatic precipitation, and low SO₂-SO₃ conversion catalyst. At a minimum, the DRI permits should contain a limit on the potential to emit sulfuric acid mist to assure the source does not trigger PSD review, sufficient monitoring, reporting and recordkeeping to assure compliance, and a low conversion SO₂-to-SO₃ catalyst.

LDEQ Response to Comment No. VII.38

The commenter makes assumptions of sulfuric acid mist formation that are not technically supported. LDEQ's review of available literature discovered very little evidence for the commenter's assumed conversion rates of SO₂ into sulfuric acid mist for natural gas combustion sources, and cannot agree that they are technically sound. LDEQ has placed requirements in the permit for the applicant to conduct stack tests on all sources that employ SCR's, including tests for sulfuric acid mist.

Sulfur dioxide emissions from each boiler are limited to 0.09 lbs/hr, and from each reformer at 3.16 lbs/hr. If the commenter's assumptions are correct, approximately 3% of SO₂ will be converted to SO₃. So, under the commenter's assumptions, SO₃ emissions from each boiler would be 0.0027 lbs/hr and from each reformer would be 0.095 lbs/hr. At these emissions levels, should sulfuric acid emissions exist, add on control would be impractical.

The applicant is required to install and operate an acid gas scrubber as part of the BACT determination for emissions of greenhouse gases. The PSD-LA-741 permit requires the installation of acid gas scrubbing achieving 95% capture and control of SO₂ emissions. The lack of a redundant Title V requirement to install and operate the same device for SO₂ control as for CO₂e control does not invalidate either the PSD permit or the Title V permit, or fail to "prevent Nucor from not scrubbing the top gas."

Comment No. VII.39

Permit 2560-000281-VI and Permit PSD-LA-751 violate 42 U.S.C. § 7475(a) because LDEQ must -- but did not -- consider or determine BACT for sulfuric acid mist emissions from pig iron sources that will employ SCR. We compared the emissions reported in the initial and modified pig iron Part 70 permits, as summarized in the Emission Rates for Criteria Pollutants table in each permit. The results of our comparison are summarized in Exhibit 1. It is important to note that although the emission rates presented in the Emission Rates for Criteria Pollutants table in the modified pig iron Part 70 permit appear to reflect installation of SCR, the emissions limitations in the Specific Requirements do not reflect installation of SCR.

The emissions of NO_x were reduced in the Modified Application by proposing to install selective catalytic reduction or SCR on nine units; by eliminating the HRSG bypass vents; and by making other minor modifications to the emission calculations. The installation of SCR to control NO_x will result insignificant increases in other regulated NSR pollutants.

Exhibit 3a compares the NO_x emissions in the initial pig iron Part 70 permit with those in the modified pig iron Part 70 permit in the Emission Rates for Criteria Pollutants tables. This comparison, coupled with the emission calculations in Appendix C to the Modification Application indicates that NO_x emissions from nine sources were reduced by proposing to install SCR as follows:

- NO_x emissions from Coke Battery FGD stacks (COK-11/211) reduced 90% using SCR;
- NO_x emissions from MEROS System Sinter Vent Stack (SIN-I01) reduced 90% using SCR;
- NO_x emissions from Topgas Boilers 1-4 (PWR-I011104) and Top gas Boiler cap (PWR-100) reduced 88% using SCR;
- NO_x emissions from PCI Mill Vent (PCI-I01) reduced 95% using SCR;
- NO_x emissions from Blast Furnace 1 Hot Blast Stoves Common Stack (STV-I01) reduced 75% using SCR.

The SCRs increase the potential to emit sulfuric acid mist, PM₁₀, and PM_{2.5}. Thus, PSD' review is required under LAC 33:III.509.K, which requires a BACT analysis for these pollutants plus a source impact analysis for all PSD-regulated pollutants under LAC 33:III.509.K. These pollutants were not addressed in the Modified Pig Iron Application. A selective catalytic reduction unit consists of a metal frame placed in the flue gas path that is stuffed with blocks of catalyst with openings to allow the gas to pass through. The catalyst consists of an inert substrate impregnated with “active” elements such as vanadium and molybdenum that convert NO_x into nitrogen gas and water in the presence of ammonia. The ammonia is injected into the flue gas ahead of the SCR. A small amount of the ammonia does not react with NO_x and slips through the catalyst. This ammonia is known as “ammonia slip.”

It is well known that the SCR catalyst also converts some of the SO₂ in the flue gases to sulfur trioxide (SO₃). The sulfur trioxide combines with water in the combustion gases and is converted into very small liquid droplets of sulfuric acid (H₂SO₄), called sulfuric acid mist or SAM, before it leaves the stack. *See, e.g., R.K. Srivastava and others, Emissions of Sulfur Trioxide from Coal-Fired Power Plants, Air & Waste Manage. Assoc., June 2004, v. 54, pp. 750-762, p. 750; EPRI, Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Version 2010a, Technical Update, April 2010, p. 3-3; J.I. Gmitro and T. Vermeulen, Vapor-Liquid Equilibria for Aqueous Sulfuric Acid, Am. Inst. Ch. Eng. Journal, v. 10, no. 5, Sept. 1964, pp. 740-76. The extent of this oxidation depends on the catalyst formulation and SCR operating conditions and can range from 0.1 % to 3%. See EPRI, April 2010, p. 3-3; Srivastava et al., June 2004, p. 755-756; Nick Irvin and Larry S. Munroe, A Review of Sulfuric Acid Formation and Behavior in Coal-Fired Power Plants, Mega, 2006. In other words, from 0.3% to 3% of the SO₂ in the flue gases at the entrance to an SCR is oxidized to SO₃. A publication by EP A and industry experts in a noted, referred journal explains:*

“It is well known that the catalyst used in the selective catalytic reduction (SCR) technology for nitrogen oxides control oxidizes a small fraction of the sulfur dioxide in the flue gas to SO₃. The extent of this oxidation depends on the catalyst formulation and SCR operating conditions. Gas-phase SO₃ and sulfuric acid, on being quenched in plant equipment (e.g., air preheater and wet scrubber), result in fine acidic mist, which can cause increased plume opacity and undesirable emissions.”

Research has developed catalysts that are capable of achieving SO₂ to SO₃ conversion rates at the lower end of the range. However, these lower conversion rates are achieved by reducing the amount of active ingredient necessary to reduce NO_x. Thus, a larger volume of a more expensive catalyst is required and is generally only selected when high concentrations of SO₂ are present in the exhaust gases. *See* Isato Morita and others, Development and Operating Results of Low SO₂ to SO₃ Conversion Rate Catalyst for DeNO_x Application; Haldor Topsoe, DNX - Topsoe SCR DeNO_x Catalysts Oxidation of SO₂ into SO₃, last accessed Jan. 1, 2011 at http://www.topsoe.com/business_areas/flue_and_waste_gas/~media/PDF%20files/Scr_d_enox/Topsoe_scr_oxidation.ashx; Anthony C. Favale and others, Application and Operating Results of Low SO₂ to SO₃ Conversion Rate Catalyst for DeNO_x Application at AEP Gavin Unit 1, Proceedings of the 2006 Environmental Controls Conference, U.S. Department of Energy, National Energy Technology Laboratory.

Sulfuric acid mist emissions are routinely included in emission calculations to determine if a modification is major for purposes of PSD. *See, e.g.*, PSD Applications for Trimble (KY), Glades (FL), Weston 4 (WI), and Santee Cooper Cross (NC). PSD review is required if the potential to emit any regulated pollutant equals or exceeds its significance threshold. The significance threshold for sulfuric acid mist is 7 ton/yr. Thus, if the proposed SCRs cause an increase in SAM emissions of 7 ton/yr or more, the modified facility triggers PSD review, requiring a BACT analysis for SAM and a source impact analysis pursuant to LAC 33:III.509. The Modified Pig Iron Application did not consider this byproduct of SCR use and the draft Specific Requirements do not include any limits on either SAM or the SCR components that would create it. Thus, we estimated the increase in SAM emissions for the nine units that would be retrofit with SCR. Our calculations are summarized in Exhibit 3d and 3e. The location of the SCR in the flue gas train and the type of catalyst determine the amount of sulfuric acid mist. The permit record does not disclose this information and the Specific Requirements do not place any limits related to the SCRs. Thus, the potential to emit SAM is unconstrained by design or emission limitations.

Three of the affected units control SO₂ emissions using a dry flue gas desulfurization system, COK-III, COK-211, and SIN-101. The SCR could be located either before or after the FGD. If located before the FGD, particulate matter and other substances in the flue gases could plug and deactivate the SCR catalyst, but the downstream FGD would remove 90-99% of the SAM. If the SCR were located after the FGD, the flue gases would likely have to be reheated to SCR operating temperature. The choice depends on engineering and economic analyses and information that is not in the permit record. Thus, we considered both cases.

Assuming a 3% conversion catalyst (all layers) located before the FGD, the SCR would increase the potential to emit SAM by 446 ton/yr. If the same SCR were located after the FGD, it would emit 403 ton/yr of SAM. Assuming a 0.5% conversion catalyst (all layers) located before the FGD, the SCR would increase the potential to emit SAM by 74 ton/yr. The same SCR located after the FGD would emit 67 ton/yr of SAM. Even if it were feasible to achieve the proposed NO_x reductions using a 0.1 % catalyst for all layers, the SAM emissions would still range from 13 to 15 ton/yr, exceeding the 7 ton/yr significance threshold.

Similarly, as discussed above, the use of SCR on the reformers and package boilers in the DRI process will cause SAM emissions from those sources. Because these SAM

emissions are the result of the same “project” that will cause SAM emissions from the pig iron sources, the DRI and pig iron SAM emissions -- including SAM emissions from the coke ovens, as described in Zen-Noh's comments to the pig iron PSD permit -- must be evaluated together for the purposes of PSD applicability and the ambient air quality analysis.

As noted above, SAM emissions from the pig iron SCR sources alone will exceed the significance level. Nucor must obtain a PSD permit in order to install SCR on the pig iron and DRI sources. This could be achieved through the DRI PSD permit or, preferably, in a new PSD permit for the aggregate DRI-pig iron facility. The PSD permit for SCR must include a BACT analysis for SAM emissions and, as such, likely will include specific conditions on the type of SCR catalyst, the maximum allowable SO₂ to SO₃ conversion rate, and BACT emission limitations. The PSD permit must also include an air quality impact analysis for SAM emissions. Last, the BACT analysis and air quality impact analysis must be made available for public review and comment and, pursuant to 42 U.S.C. § 7475(a), LDEQ must hold another public hearing after the air quality impact analysis is published.

LDEQ Response to Comment No. VII.39

Nucor is not permitted to directly emit any sulfuric acid mist from these sources. However, a portion of sulfur dioxide emissions may be converted to sulfur trioxide in the atmosphere, and become a precursor of sulfuric acid mist. Reducing SO₂ emissions is the only way to reduce the possibility of the secondary formation of sulfur trioxide and sulfuric acid mist. Sulfur dioxide will be controlled by BACT and was properly addressed in the facility's permits.

The commenter cites several technical documents studying sulfuric acid mist emissions from coal-fired power plants as justification for the presence of sulfuric acid mist emissions at the Nucor pig iron facility. It should be noted that the Nucor facility does not propose to construct a coal-fired electric utility boiler. Although the coke ovens will process coal, and the HRSG units reclaiming heat from the process will generate steam to produce electricity, conflating this process with coal-fired electric boilers is not technically sound for several reasons. Metallurgical coal has significantly lower sulfur content than most thermal coals, and the majority of the coal mass entering a coke oven is retained in the coke product, including sulfur compounds, as opposed to fully combusted down to ash as in boiler operations. LDEQ has placed requirements in the permit for the applicant to conduct stack tests on all sources that employ SCR's, including tests for sulfuric acid mist.

Comment No. VII.40

Permit 2560-000281-VI and Permit PSD-LA-751 violate 42 U.S.C. § 7475(a) because LDEQ must -- but did not -- consider or determine BACT for PM/PM10/PM2.5 emission increases from pig iron sources that will employ SCR. Under Louisiana regulations, PM10 is “particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers as measured by the methods specified in 40 CFR Part 52.” and “particulate matter emissions” is “all finely divided solid or liquid material, other than uncombined water, emitted to the ambient air as measured by Method 5 in 40 FR Part 60, Appendix A, as incorporated by reference at LAC 33:III.3003. LAC 33:III.111.

The sulfuric acid mist emissions discussed above are PM, PM10 and PM2.5 under these definitions as it is present as either a mist or a vapor at the stack. When present as an aerosol, it meets the first part of this definition (airborne finely divided liquid material)

and when present as a gas, e.g., SO₃ or H₂SO₄, it meets the second part, a vapor that PM₁₀ as measured by EPA Method 201. When present as a gas, it is condensable PM₁₀ and measured by EPA Method 202. The PSD significance threshold for PM is 40 ton/yr, for PM₁₀ it is 15 ton/yr and for PM_{2.5}, it is 10 ton/yr. Thus, based on the calculations for SAM in Exhibit 3d and 3e, the proposed SCRs also trigger PSD review for PM, PM₁₀ and PM_{2.5}.

In addition to direct PM/PM₁₀/PM_{2.5} emissions from SAM, the SCRs will also emit 90 tons per year of ammonia, which is a precursor to fine particle formation in the atmosphere. Ammonia gas emitted from the SCR undergoes chemical reactions in the atmosphere, forming secondary particulate matter. The emission calculations indicate that significant amounts of ammonia will be emitted, primarily because the SCRs are proposed with high ammonia slips. Ammonia can react with SAM in the stack to form ammonium sulfate, which increases the emission rate of PM₁₀ because ammonium sulfate has a higher molecular weight than SAM. It is feasible to design SCR with lower slips, which will reduce PM₁₀ caused by ammonium sulfate and un-reacted ammonia slips.

Table –
Ammonia Emitted by the SCRs

Source	Ammonia (ton/yr)
COK-111	21.82
COK-211	21.82
SIN-101	10.38
PWR-101	5.28
PWR-102	5.28
PWR-103	5.28
PWR-103	5.28
STV-101	11.11
PCI-101	0.39
TOTAL	86.64

As noted above, Nucor must obtain a PSD permit in order to install SCR on the pig iron sources. This could be achieved through the DRI PSD permit or, preferably, in a new PSD permit for the aggregate DRI-pig iron facility. The PSD permit for SCR must include a BACT analysis for PM/PM₁₀/PM_{2.5} emissions and, as such, likely will include specific conditions on the type of SCR catalyst, the maximum allowable SO₂ to SO₃ conversion rate, the maximum allowable NH₃ slip, and BACT emission limitations. The PSD permit must also include an air quality impact analysis for PM/PM₁₀/PM_{2.5} emissions. The BACT analysis and air quality impact analysis must be made available for public review and comment and, pursuant to 42 U.S.C. § 7475(a) and (e), DEQ hold another public hearing after the air quality impact analysis is published. LDEQ must also perform a Class I impact analysis pursuant to 42 U.S.C. § 7475(d) and must present the Class I impact analysis to the Federal Land Manager.

LDEQ Response to Comment No. VII.40

LDEQ is aware that SO₃ may react with ammonia and water to form ammonium sulfate and ammonium bisulfate; however, such emissions may be minimized by optimizing the injection rate of ammonia during stack testing of the sources in question. There is no evidence to suggest that

these sources will not be able to comply with the PM₁₀ limitations set forth in Permit No. 2560-00281-V1.

Additionally, USEPA has issued guidance contrary to the commenter's claim of ammonia as a PM_{2.5} precursor, stating that "due to the considerable uncertainty related to ammonia as a precursor, our final rules do not require ammonia to be regulated as a PM_{2.5} precursor" (73 FR 28330). Claims that emissions of sulfuric acid mist will exist are not supported by this comment.

Comment No. VII.41

Permit No. PSD-LA-751 should be denied because the permit must -- but does not include a BACT determination for lead emissions. PSD review is required if the potential to emit any regulated pollutant equals or exceeds significance thresholds. The significance threshold for lead is 0.6 ton/yr. Thus, if the DRI process emits 0.6 ton/yr or more lead, Nucor must prepare a source impact analysis and a BACT analysis for lead. LAC 33:III.509. The permit record does not contain either.

Rather, the DRI application indicates that lead emissions from the existing pig iron permit are 0.375 ton/yr and from the proposed DRI facility, 0.003 ton/yr. However, lead emissions are underestimated. Further, if lead emissions from the pig iron facility are included, lead emissions exceed 0.6 ton/yr, requiring PSD review.

First, the emission calculations for both the DRI and pig iron facilities do not include any lead emissions from material handling and transport, such as from storage piles, conveyors, loading/unloading operations, and truck traffic over roads, e.g., DOC-101, PIL-102, DRI-101/201, DRI-102, DRI-104, DRI-105/205. The materials handled at these facilities contain elevated concentrations of lead, *see* Portland Cement Association, Mercury and Lead Content in Raw Materials, PCA R&D Serial No. 2888, 2006, Table 6, which will be emitted with the total suspended particulate matter. The LDEQ should require that the applicant supply the lead content of materials handled at each of these sources and use the data to estimate lead emissions from fugitive dust sources. However, as a rough estimate, if it is assumed that the weighted average lead content in the materials handled is 100 ppm, the lead emissions from material handling will be about 0.033 ton/yr.

Second, the major disclosed source of lead from the DRI process is the reformers (DRI-108/208). The reformer emission calculations are based on a lead emission factor of 4.90 10⁻⁶ lb/MMBtu. This emission factor is simply stated, with no citation to a basis. The same emission factor is used for package boilers, which burn only natural gas. However, the fuel burned in the reformer is not natural gas, but rather a blend of natural gas and spent reforming gas from the Shaft Furnace. As iron ores contain high concentrations of lead and the Shaft Furnace operates at elevated temperatures and generates large amounts of lead-containing dust, it is likely that some of the lead from the iron ores is transferred to the spent reforming gas as particulate and gaseous lead that is emitted at the reformer stack. Lead emissions in other blends of process and natural gas range up to 7.73 10⁻³ lb/MMscf (7.57 10⁻⁶ lb/MMBtu) or 15 times higher. *See* http://www.arb.ca.gov/app/emsinv/catef_list.php. If this emission factor is used to calculate potential to emit from the reformers, lead emissions increase from <0.001 ton/yr to 0.106 ton/yr.

Third, the emission calculations to determine whether PSD applies must be based on the potential to emit, or the maximum emissions as restricted by any controls. The lead

emissions calculated in the DRI Application are not potential to emit as they are based on the average hourly emission rate and the assumed number of hours of operation of each lead emission source. As the draft permits contain no enforceable conditions on the hours of operation or the throughput for any of the sources, nor any basis for any of the emission factors used to calculate lead emissions, these calculations do not represent potential to emit. Eliminating the Reformer, estimated above, the potential to emit of remaining admitted lead sources is at least 0.018 lb/hr.

Finally, as discussed elsewhere, the modified pig iron facility and the DRI facility should be aggregated and permitted as a single source. Thus, the lead emission from the pig iron facility must be included in the lead potential to emit calculation. Nucor estimated these emissions at 0.375 ton/yr. The DRI contribution of 0.157 ton/yr plus Nucor's pig iron lead estimate add up to 0.532 ton/yr, just shy of the 0.6 ton/yr PSD significance threshold. Thus, at a minimum, the DRI permit should contain a limit on the potential to emit lead to assure the source does not trigger PSD review for lead.

However, the pig iron estimate is low, as Nucor failed to include lead emissions from material handling and transport and failed to calculate potential to emit based on 8,760 hour per year and the maximum hourly emission rate. Nucor should be required accurately to quantify aggregate lead emissions from the DRI-pig iron facility, for all potential sources of lead emissions and without using limits on hours of operation unless the limits are federally enforceable limits incorporated in a Specific Requirement. If the aggregate lead emissions exceed 0.6 ton/yr, as they almost certainly will, Nucor should be required to conduct a full PSD review, including BACT and an ambient air quality analysis for lead emissions.

Nucor must quantify emissions from wastewater sources in the DRI process. Unlike the pig iron process, the DRI process will generate process wastewater, and, since the DRI process is now phase 1 of the overall project, DRI process wastewater will be discharged. See EDMS Doc. 7724385. The exact nature of the process wastewater sources is unclear because Nucor failed to account for wastewater air emission sources in the DRI permit applications and has not submitted an application for an LPDES permit to discharge DRI process wastewater. Nonetheless, information published by the Lo-Cat and SulfaTreat vendors -- two systems Nucor is considering for the acid gas absorption vent -- indicate that this treatment process will be a source of process wastewater. CITE. Given the nature of the acid gas absorption vent, this process wastewater is likely to contain hydrogen sulfide and other total reduced sulfur ("TRS") compounds, which are regulated NSR pollutants and Louisiana Toxic Air Pollutants. Hydrogen sulfide and TRS generally are also extremely volatile, which means that they likely will be emitted into the atmosphere if in fact they are contained in the acid gas absorption vent treatment system blowdown. Nucor should be required to quantify these and all emissions from process wastewater sources, and to implement appropriate control technologies, including BACT if hydrogen sulfide or TRS emissions will exceed the significance level. Nucor should also be required to submit an application for and obtain an LPDES permit applicable to the DRI process before commencing construction of the DRI process.

LDEQ Response to Comment No. VII.41

If the Potential to Emit for lead emissions or actual lead emissions exceed the PSD threshold, the facility will have violated the PSD regulations. The LDEQ permits issued are based upon emission estimates provided by the applicant. Nucor is permitted to emit 0.003 tons/year of lead from the DRI Plant. Nucor must comply with this limit.

The commenter's assertions of lead emissions from the handling of bulk dry materials at the proposed facility are unsupported, and assumptions of the specific lead content of vaguely defined "materials" are wholly without merit. Emissions of lead have been understood by LDEQ to mean emissions of elemental lead, not lead compounds or alloys. Elemental lead is most frequently, but not exclusively, generated by the combustion of fuels containing lead or lead compounds in varying quantities, such as coal or natural gas.

The emission factor used for determining lead emissions from combustion sources, namely the reformers and package boilers, are consistent with the factor provided by AP-42 for the combustion of natural gas, listed in Table 1.4-2. This factor is merely converted into units of mass per unit of energy input.

The emission limits for lead established in the permit were formed on the basis of the emission factor supplied by AP-42, and the maximum hours of operation expected by the source. The operator must either maintain hours of operation below the threshold presented in the permit application emission calculations, or demonstrate that hourly emissions are less than predicted by AP-42 in order to maintain compliance with the permit.

Comment No. VII.42

Nucor must quantify emissions from wastewater sources in the DRI process. Unlike the pig iron process, the DRI process will generate process wastewater, and, since the DRI process is now phase 1 of the overall project, DRI process wastewater will be discharged. See EDMS Doc. 7724385. The exact nature of the process wastewater sources is unclear because Nucor failed to account for wastewater air emission sources in the DRI permit applications and has not submitted an application for an LPDES permit to discharge DRI process wastewater. Nonetheless, information published by the Lo-Cat and SulfaTreat vendors -- two systems Nucor is considering for the acid gas absorption vent -- indicate that this treatment process will be a source of process wastewater. CITE. Given the nature of the acid gas absorption vent, this process wastewater is likely to contain hydrogen sulfide and other total reduced sulfur ("TRS") compounds, which are regulated NSR pollutants and Louisiana Toxic Air Pollutants. Hydrogen sulfide and TRS generally are also extremely volatile, which means that they likely will be emitted into the atmosphere if in fact they are contained in the acid gas absorption vent treatment system blowdown. Nucor should be required to quantify these and all emissions from process wastewater sources, and to implement appropriate control technologies, including BACT if hydrogen sulfide or TRS emissions will exceed the significance level. Nucor should also be required to submit an application for and obtain an LPDES permit applicable to the DRI process before commencing construction of the DRI process.

LDEQ Response to Comment No. VII. 42

The commenter fails to cite a source supporting his concerns that the SulfaTreat sulfur treatment system proposed by the applicant will be a source of wastewater, or that such wastewater will "likely to contain hydrogen sulfide and other total reduced sulfur ("TRS") compounds". LDEQ's review of the SulfaTreat technology determined that it is a fixed-bed, solid catalyst substrate, typically placed inside of the duct for the control of hydrogen sulfide. Hydrogen sulfide and TRS compounds bind to the solid catalyst, forming iron pyrite and similar solids. LDEQ was unable to find reference to wastewater discharges from SulfaTreat systems, but found considerable information on the use of SulfaTreat in reducing odors from municipal wastewater systems.

The contact water systems at the DRI facility are anticipated to collect a great deal of mineral particulate high in iron content. Due to the nature of the process, hydrogen sulfide, VOC compounds and TRS compounds are not expected to be present.

Nucor is required to have an approved LPDES permit prior to discharging any wastewater.

Comment No. VII.43

PSD Permit No. PSD-LA-75I should be denied and PSD Permit No. PSD-LA-740 should be withdrawn or terminated because Nucor has not and cannot demonstrate compliance with the 1-hour NO₂ NAAQS. The one-hour NO₂ NAAQS takes the form of a three-year average of the 98th-percentile of the annual distribution of daily maximum one-hour concentrations, which cannot exceed 100 ppb. *See* USEPA, Guidance Concerning the Implementation of the 1-hour NO₂ NAAQS for the Prevention of Significant Deterioration Program, June 29, 2010, p.1. This standard is to be verified using USEPA's AERMOD air dispersion model, which produces air concentrations in units of µg/m³. The one-hour NO₂ NAAQS of 100 ppb is equal to 188 µg/m³. The 98th- percentile of the annual distribution of daily maximum one-hour concentrations corresponds to the eighth-highest value at each receptor for a given year.

USEPA's one-hour NO₂ NAAQS also addresses the concept of one-hour NO₂ NAAQS significant impact level, or "SIL."

In this guidance, EPA recommends an interim 1-hour NO₂ SIL value of 4 ppb. To determine initially whether a proposed project's emissions increase will have a significant impact (resulting in the need for a cumulative air quality analysis), this interim SIL should be compared to either of the following:

- The highest of the 5-year averages of the maximum modeled 1-hour NO₂ concentrations predicted each year at each receptor, based on 5 years of National Weather Service data; or
- The highest modeled 1-hour NO₂ concentration predicted across all receptors based on 1 year of site-specific meteorological data, or the highest of the multi-year averages of the maximum modeled 1-hour NO₂ concentrations predicted each year at each receptor, based on 2 or more, up to 5 complete years of available site-specific meteorological data (See USEPA, Guidance Concerning the Implementation of the 1-hour NO₂ NAAQS for the Prevention of Significant Deterioration Program, June 29, 2010, p.12).

USEPA's recommended interim one-hour NO₂ SIL of 4 ppb equals 7.5 µg/m³.

On September 16, 2010, Nucor modeled NO₂ emissions from the aggregate pig iron/DRI components of their facility. This analysis determined that the highest five-year average of the maximum modeled one-hour NO₂ concentrations for each year at each receptor is 7.4 µg/m³, See EDMS Doc. 7664737, p. 75. This is slightly below USEPA's recommended interim one-hour NO₂ SIL (7.5 µg/m³).

On October 13, 2010, Nucor submitted their Title V and Part 70 Permit Modification Application for Permit Nos. 2560-00281-V0 and PSD-LA-740. *See* EDMS Doc. 7731641, p. 189. In this permit application, Nucor states:

Nucor determined that AERMOD cumulative modeling predicts order-of magnitude

exceedances of the 1-hour NO₂ NAAQS, even without contributing sources from the Nucor NSLA and DRI facilities. *See* EDMS Doc. 7731641, p. 211.

We have not been able to locate Nucor's cumulative one-hour NO₂ modeling analysis that is the basis for this statement.

Nucor's permit application also states: "Nucor's modeling shows that the combined emissions of the NSLA and DRI facilities, even after the removal of one blast furnace and associated equipment, will not meet the SIL level of 4% of the 1-hour NO₂ NAAQS." *See* EDMS Doc. 7731641, p. 212.

We have not been able to locate Nucor's one-hour NO₂ modeling analysis that is the basis for this statement.

On October 22, 2010, Nucor updated their September 16th NO₂ modeling analysis with revisions to NO₂ emissions from sources DRI110 and DRI210 (the hot flares from DRI units 1 and 2, respectively). This analysis determined that the highest five-year average of the maximum modeled one-hour NO₂ concentrations for each year at each receptor is 7.45 µg/m³. *See* EDMS Doc. 7731649, p.12. This is over 99% of USEPA's recommended interim 1-hour NO₂ SIL (7.5 µg/m³).

We examined Nucor's October 22, 2010 one-hour NO₂ analyses, and were able to recreate their modeling results. We determined that the highest five-year average of the maximum modeled one-hour NO_x concentrations for each year at each receptor is 9.92695 µg/m³. This value exactly matches Nucor's October 22, 2010 peak one-hour NO_x result, even though Nucor used a proprietary post-processing program, apparently called NO2POST. The form of USEPA's interim one-hour NO₂ SIL does not require postfile post-processing, and can be achieved with AERMOD and annual plotfiles of peak modeled one-hour NO₂ concentrations.

Nucor's determination that the highest five-year average of the maximum modeled one-hour NO₂ concentrations for each year at each receptor is 7.45 µg/m³ is reached by multiplying the 9.92695 µg/m³ NO_x value by 0.75, which is USEPA's ambient ratio method ("ARM") for annual-average modeling (*See* LDEQ-EDMS Document 7664737, page 70 of 86). This is also known as a "Tier 2" NO to NO₂ conversion technique. This is a questionable practice for one-hour NO₂ modeling.

USEPA's guidance on using the ARM for verifying compliance with the one-hour NO₂ NAAQS is as follows:

Tier 2 may also apply to the 1-hour NO₂ standard in many cases, but some additional consideration will be needed in relation to an appropriate ambient ratio for peak hourly impacts since the current default ambient ratio is considered to be representative of "area wide quasi-equilibrium conditions."

See USEPA, Guidance Concerning the Implementation of the 1-hour NO₂ NAAQS for the Prevention of Significant Deterioration Program, June 29, 2010, p.15. Nucor has not provided any additional consideration in relation to an appropriate ambient ratio for peak hourly impacts." They simply used the annual-average modeling ARM, with no justification that it applies to peak one-hour impacts in the area surrounding their proposed pig iron/DRI facility. Stated simply, Nucor has failed to demonstrate that their aggregate facility will cause one-hour NO₂ impacts below the

interim SIL. This is particularly problematic since Nucor has identified “order-of-magnitude exceedances of the 1-hour NO₂ NAAQS, even without contributing sources from the Nucor NSLA and DRI facilities.”

Furthermore, it is clear that Nucor revised the “stack” exit velocities of the coke battery pushing emissions for their one-hour NO₂ NAAQS modeling. The coke battery pushing emissions are modeled as sources COK102 and COK202. In their pig iron permit application, Nucor modeled COK102 and COK202 emissions with an exit velocity of 1.0 meter/second, but modeled these emissions with an exit velocity of 5.0 meters/second in their one-hour NO₂ NAAQS analysis for the combined emissions from pig iron and DRI facility components. Nucor failed to provide any justification for increasing the coke battery pushing exit velocity, other than changing the value on the emission inventory questionnaire for these sources. *See* EDMS Doc. 7725815, pp.19 and 28. These emission inventory questionnaires were revised in October, 2010.

Nucor’s one-hour NO₂ NAAQS analyses in September and October, 2010, both used the revised coke battery pushing exit velocities. Thus, Nucor’s revision to the COK102 and COK202 exit velocities in their September 16, 2010 modeling pre-dates their revised emission inventory questionnaires. In addition, Nucor’s PM₁₀ and PM_{2.5} modeling of sources COK102 and COK202 used an exit velocity of 1.0 meter/second, even though these analyses were performed in October and November, 2010.

We revised Nucor’s one-hour NO₂ NAAQS modeling analysis by resetting COK102 and COK202 exit velocities to 1.0 meter/second. This is the value used in Nucor’s own PM₁₀ and PM_{2.5} modeling and throughout their pig iron permit application.

Our revised one-hour modeling analysis determined that the highest five-year average of the maximum modeled one-hour NO_x concentrations for each year at each receptor is 10.07 µg/m³. Even if we applied the annual-average Tier 2 ARM of 0.75 for converting NO to NO₂ (which we believe is inappropriate for one-hour averaging periods), we calculate that the highest five-year average of the maximum modeled one-hour NO₂ concentrations for each year at each receptor is 7.55 µg/m³. In other words, using Nucor’s original exit velocity for sources COK102 and COK202 (which LDEQ defended in their response to comment #277 for Nucor’s pig iron permit application), will result in one-hour NO₂ concentrations above USEPA’s interim SIL.

And as we commented on Nucor’s one-hour SO₂ impact analyses, Nucor’s coke pushing fugitive emissions occur intermittently over a rather large area, and are most realistically modeled as an area-polygon emission source. We did not have enough time to remodel Nucor’s COK102 and COK202 NO_x emissions as an AREAPOLY source, but we would expect significantly higher impacts using this method.

For reasons described above, Nucor has failed to demonstrate that their facility will not cause or contribute to one-hour NO₂ NAAQS violations. Nucor must prepare a cumulative one-hour NO₂ NAAQS modeling analysis, including all other NO_x emitting sources in the area surrounding the proposed Nucor facility.

LDEQ Response to Comment No. VII.43

LDEQ examined the applicant’s 1-hr NO₂ modeling submittal in detail, with input from US EPA Region 6, and determined that the proposed emissions will not cause or contribute to a violation of the new 1-hour NO₂ NAAQS. LDEQ determined that the ambient ratio method (ARM) was

appropriate in this case for several reasons, including the fact that peak concentrations occurred at receptors some distance away from the site, and occurred during morning hours prior to significant atmospheric mixing action that would be anticipated in the warmer afternoon hours. LDEQ found no reason to rule the established ARM method was inappropriate for this case.

At no time did LDEQ defend a specific exit velocity from sources COK-102 and COK-202 in Response to Comment #277, as alleged. LDEQ stated its position that emissions from coke oven pushing are not properly characterized as fugitive emissions, as the commenter then asserted, and that the proposed stack parameters were adequately approximated by the proposed stacks. LDEQ concluded its response by stating “The stack heights, stack velocities, and locations are the same as those listed and in the permit application, and Nucor will be required to meet these specifications. Since the facility is in the preliminary design phase, Nucor can create designs that match the characteristics used to establish the stack parameters used in the calculations and modeling. With the stack characteristics in the permit, Nucor has demonstrated that it will not cause or significantly contribute to an exceedance of the NAAQS, PSD increment, or AAS.” We consider this response to remain valid.

Nucor did not submit the modeling referenced on pages 211-212 of EDMS Document No. 7731641 nor is the facility required to do so. The referenced modeling was done during preliminary design considerations and is mentioned in the permit application for informational purposes. The only modeling that is required to be submitted is PSD modeling based upon the permitted design, the basis for which was submitted in the permit application.

40 CFR 51 Appendix W describes a multi-tiered approach to modeling NO_x emissions. Because the standard is in the form of NO₂, not NO_x, EPA recognizes that assuming all NO_x is NO₂ will be overly conservative. In the multi-tiered approach, the initial screen uses a Gaussian model to estimate the maximum concentration and assumes a total conversion of NO to NO₂. If the results are too conservative, they can be multiplied by an empirically derived NO₂/NO_x value of 0.75. The NO₂/NO_x factor of 0.75 can be applied to the NO₂ significance modeling¹³³ as well as to refined modeling.

The majority of NO_x emissions are initially emitted as NO from source stacks. This is acknowledged by EPA’s Addendum to the AERMOD Implementation Guide¹³⁴, which allows a default 0.10 in-stack ratio of NO₂/NO_x in the Plume Volume Molar Ratio Method (PVMRM). Presumably, as this is a default value, this value is also conservative. Indeed, the San Joaquin Valley Air Pollution Control District has compiled a list of NO₂/NO_x ratios¹³⁵ that can be used as default in-stack ratios. All of the listed sources have a recommended ratio of less than 0.20; most of the recommended values are below 0.10.

Additionally, in many applications, the maximum impact due to the facility being modeled occurs in close proximity to the plant’s emission sources. For the Nucor Plant, the receptor point having the maximum 1-hour NO₂ concentration (averaged over the 5 year meteorological database) was approximately 1350 meters from the DRI reformer stacks (DRI108 and DRI208). Typically, with such a short distance from the source to the maximum near field impact, the

¹³³ March 15, 2002 memo from Daniel J. deRoeck to Richard Daye, available at <http://www.epa.gov/ttn/nsr/gen/ratio.pdf>

¹³⁴ October 2009 version is available on EPA’s SCRAM website, http://www.epa.gov/ttn/scram/dispersion_prefrec.htm

¹³⁵ Available at http://www.valleyair.org/busind/pto/Tox_Resources/Assessment%20of%20Non-Regulatory%20Option%20in%20AERMOD.pdf

timeframe is too short for a majority of the NO to convert to NO₂. The OLM/ARM Workgroup noted in its May 27, 1998 document¹³⁶ on the use of the ambient ratio method (ARM) that the original description of the ARM indicated the distance where the typical NO_x composition within the plume has stabilized could be greater than 10 kilometers from the emission source and that the ARM would conservatively estimate near-field NO₂ impacts. Also, as noted in the June 2005 MACTEC Report for the Alaska Department of Environmental Conservation Division of Air Quality on the evaluation of bias in the PVMRM¹³⁷, “Bofinger et al. (1986) states that ‘the plume centerline ratio of NO₂ to total oxides of nitrogen (NO_x) does not exceed a value of 80% conversion for plume ages of the order of seven hours.’”¹³⁸

Based upon the fact that NO_x is generally emitted as NO and the highest receptor concentrations are near the facility, it is unlikely that most of the NO will have converted to NO₂ at these receptors. Therefore, the application of the national annual default conversion factor (0.75) is reasonable as applied to predicted NO_x concentrations at this distance. Even the June 28, 2010¹³⁹ 1-hour NO₂ modeling guidance does not specifically disallow the use of the 0.75 ARM. It simply states, “such application of Tier 2 for 1-hour NO₂ compliance demonstrations **may** need to be considered on a source-by-source basis in **some** cases [emphasis added].”

The conversion of NO to NO₂ is also dependent on available ozone. Available ozone causes the conversion to NO₂ to increase. Looking at the meteorological conditions for the maximum predicted 1-hour average concentration for the receptor point having the maximum 5-year average 1-hour NO₂ concentration (705889, 3328026) the following conditions are noted:

Year	Concentration (µg/m ³)	Date	Hour	Temperature (°F)
2001	6.97	February 23	0900	48
2002	6.80	January 12	1100	50
2003	8.11	August 13	0800	72
2004	6.90	March 17	1000	67
2005	8.43	November 19	1000	53

Although this is only one case, it appears that most of the hours which result in the predicted highest 1-hour average for this receptor are during the winter months, mid-morning, and low temperature, which would not correlate to high ozone concentrations. These conditions support using the traditional NO₂/NO_x conversion factor of 0.75 for the 1-hour averaging period.

Looking at all of the receptors with a five-year average modeled concentration above 7.5 µg/m³, when the individual year data points for those receptors was above a modeled concentration of 7.5 µg/m³ and when ozone is mostly likely to be present (late morning and afternoon), the occurrences above 7.5 µg/m³ occur almost exclusively in colder months (November- March). During peak ozone season (May-September), the highest concentrations of NO_x (above 8.33 µg/m³) occur exclusively between the hours of 7am-9am and 8pm-11pm. During these timeframes, it is unlikely that ozone chemistry is favorable for conversion of NO to NO₂.

¹³⁶ Available at <http://www.dec.state.ak.us/air/ap/docs/sitearm.pdf>

¹³⁷ Available at http://www.epa.gov/scram001/7thconf/aermod/pvmrm_bias_eval.pdf

¹³⁸ Bofinger, N.D., P.R. Best, D.I. Cliff, and L.J. Stumer. 1986, “The oxidation of nitric oxide to nitrogen dioxide in power station plumes,” Proceedings of the Seventh World Clean Air Congress, Sydney, 384-392.

¹³⁹ Memo from Tyler Fox to the Regional Air Directors, available at http://www.epa.gov/ttn/scram/ClarificationMemo_AppendixW_Hourly-NO2-NAAQS_FINAL_06-28-2010.pdf

Finally, it should be noted that the cumulative modeling is not a PSD required modeling exercise. PSD regulation requires modeling of independent projects. The Pig Iron Facility and the DRI Facility are separate projects and should be modeled separately to determine the extent of compliance. The DRI Facility permit application included modeling¹⁴⁰. The modeling indicated a maximum 1-hour NO₂ impact of 6.14 ug/m³, with 100% conversion of NO to NO₂. This is below EPA's interim significance level of 7.5 ug/m³. Therefore, the DRI Facility is insignificant in regards to NO_x emissions, and a cumulative impact analysis is not required.

LDEQ believes that the Pig Iron Facility would likely prove to be insignificant in regards to NO_x emissions if modeled on its own, which is the proper modeling procedure for a single project, and therefore, cumulative modeling would not be required. LDEQ modeled the highest overall receptor (highest 5-year average) and the highest receptor for each individual year. Averaged over five years, all six receptors passed while assuming 100% conversion of NO to NO₂. Not only do these receptors represent the highest modeled concentrations in the cumulative modeling, but the receptors are on different sides of the plant and are able to capture different wind directions. A summary of the results of this investigation are in the table below.

UTM Coordinates		5-Year Average
704188.9	3325326	6.21
703788.9	3328926	6.66
705788.9	3332426	6.92
705888.9	3327126	6.85
712188.9	3329526	6.17
705888.9	3328026	6.88

In summary, the use of the ARM and the annual default NO₂ to NO_x ratio of 0.75 is still valid. The fact that most emissions occur as NO and the impacts occur close to the facility impedes the time required to convert NO to NO₂. Additionally, the highest concentrations of NO_x generally occur during cooler parts of the day and cooler times of the year; therefore, less ozone is available for conversion of NO to NO₂. Moreover, the cumulative modeling is not required by PSD regulation, and the DRI Facility has already demonstrated compliance with the NO₂ modeling requirements on its own.

The stack parameters for some of the Pig Iron Plant sources have been updated from the previous permit in the modification application. The plant has not been built yet, and LDEQ has no reason to believe that the new stack parameters are unreasonable. As the new stack parameters are part of the revised permit, Nucor will be held to these parameters in its final design of the facility. If these stack parameters are determined to be incorrect, Nucor will be required to modify the permit.

Nucor erroneously used the old velocity for sources COK102 and COK202 in the PM₁₀ and PM_{2.5} modeling analyses. However, the old velocity is smaller than the new velocity, and therefore, the modeling results should err on the conservative side.

Sources COK102 and COK202 were modeled as point sources. Stack parameters for these sources are included on the EIQ sheets and in the permit. Due to the nature of these sources (notably

¹⁴⁰ See page 166 of EDMS Document ID 6592414

extremely high temperature which will also lead to significant velocity), stack parameters most closely mimic the actual dispersion characteristics of the sources. The permit includes stack testing conditions for these sources. Stack testing will verify whether these stack parameters are reasonable. If the stack parameters are found to be unreasonable, the facility may be required to modify the permit.

Comment No. VII.44

PSD Permit No. PSD-LA-751 and Part 70 Permit No. 2560-00281-VI should be denied because the aggregate SO₂ emissions from the DRI-pig iron facility will cause violations of the 1-hour SO₂ NAAQS. As part of their PSD permit application for the DRI component of their facility, Nucor modeled SO₂ emissions from the DRI sources. Nucor, however, failed to model any SO₂ emissions from the pig iron sources that are also part of their aggregate facility. Had they performed this combined modeling, which we feel is an essential part of the aggregate project, Nucor would have discovered that their project will result in violations of the one-hour SO₂ NAAQS.

A. One-Hour SO₂ NAAQS

The one-hour SO₂ NAAQS takes the form of a three-year average of the 99th-percentile of the annual distribution of daily maximum one-hour concentrations, which cannot exceed 75 ppb. *See* USEPA, Applicability of Appendix W Modeling Guidance for the 1- hour SO₂ National Ambient Air Quality Standard, August 23, 2010. This standard is to be verified using USEPA's AERMOD air dispersion model, which produces air concentrations in units of $\mu\text{g}/\text{m}^3$. The one-hour SO₂ NAAQS of 75 ppb is equal to 196.5 $\mu\text{g}/\text{m}^3$. The 99th-percentile of the annual distribution of daily maximum one-hour concentrations corresponds to the fourth-highest value at each receptor for a given year.

The form of the one-hour SO₂ NAAQS requires post-processing that goes beyond the existing output capabilities of USEPA's AERMOD model. We wrote FORTRAN post-processing programs to perform these tasks, which are summarized as follows:

- For each year modeled, one-hour SO₂ concentrations for each hour and each receptor were output to an AERMOD postfile.
- We developed a FORTRAN program to read the AERMOD postfile and save the daily maximum one-hour SO₂ concentrations for each receptor modeled.
- The daily maximum one-hour SO₂ concentrations for each receptor are sorted in descending order (highest first) for each day modeled in the year.
- Using a FORTRAN program, the fourth-highest daily maximum one-hour SO₂ concentration for each receptor is extracted from the sorted data set. This is performed for each year of meteorological data modeled.
- The fourth-highest daily maximum one-hour SO₂ concentration for each receptor is then averaged across all years of modeled meteorological data. For the modeling performed with the 2001 -2005 Baton Rouge Capitol Airport data, we calculated a five-year average of the fourth-highest daily maximum one-hour SO₂ concentration for each receptor. For the modeling performed with the 2005 -2008 LDEQ Baker data, we calculated a four- year average of the fourth-highest daily maximum one-hour SO₂ concentration for each receptor.
- The highest fourth-highest multi-year average daily maximum one-hour SO₂ concentration over all modeled receptors is identified and saved.

- The appropriate background one-hour SO₂ concentration is added to the highest fourth- highest multi-year average daily maximum one-hour SO₂ concentration for verifying compliance with the NAAQS.

B. Background SO₂ Concentrations

The USEPA guidance on developing one-hour background SO₂ concentrations is as follows:

The form of the new 1-hour SO₂ standard also has implications regarding appropriate methods for combining modeled ambient concentrations with monitored background concentrations for comparison to the NAAQS in a cumulative modeling analysis. As noted in the March 23, 2010 memorandum regarding “Modeling Procedures for Demonstrating Compliance with PM_{2.5} NAAQS” (EPA, 2010b), combining the 98th percentile monitored value with the 98th percentile modeled concentrations for a cumulative impact assessment could result in a value that is below the 98th percentile of the combined cumulative distribution and would, therefore, not be protective of the NAAQS. However, unlike the recommendations presented for PM_{2.5}, the modeled contribution to the cumulative ambient impact assessment for the 1-hour SO₂ standard should follow the form of the standard based on the 99th percentile of the annual distribution of daily maximum 1-hour concentrations averaged across the number of years modeled. 122

From LDEQ, we obtained hourly SO₂ data from the Baton Rouge Capitol site for years 2004 through 2008. This is the same site used by Nucor in developing background SO₂ concentrations for use in their application modeling.

Using the hourly SO₂ data from LDEQ's Baton Rouge Capitol site, we extracted the fourth-highest daily maximum one-hour SO₂ concentration for each year of data. These results are summarized in the following table:

Year	4th high SO ₂ (ppb)	4th high SO ₂ (µg/m ³)
2004	67	175.57
2005	59	154.61
2006	62	162.47
2007	68	178.19
2008	61.8	161.94
2004 -- 2008 average:		166.56
2006 -- 2008 average:		167.53

There is little difference between the 2006 - 2008 three-year average of the fourth-highest daily maximum one-hour SO₂ concentrations (167.53 µg/m³) and the 2004- 2008 five-year average of the fourth-highest daily maximum one-hour SO₂ concentrations (166.56 µg/m³). Considering the three-year average form of the one-hour SO₂ NAAQS, we determined that a background concentration of 167 µg/m³ is the appropriate value.

C. Modeled SO₂ Emissions and Stack Parameters

As discussed above, Nucor only modeled SO₂ emissions from the DRI portion of their facility. Since Nucor failed to assess compliance with the one-hour SO₂ NAAQS using emissions from their entire facility (the pig iron plant and the DRI), we performed air dispersion modeling to evaluate this deficiency.

As did Nucor, we used USEPA's AERMOD dispersion model, v. 09292, for our SO₂ NAAQS modeling analysis. We also used Nucor's SO₂ emissions and source parameters from their DRI plant modeling. For modeling the SO₂ emissions from the pig iron plant, we used Nucor's source parameters from their combined facility one-hour NO₂ modeling analyses dated October 22, 2010, and the SO₂ emissions from the pig iron plant permit application. The modeled SO₂ emissions and source parameters we used for verifying compliance with the one-hour SO₂ emissions are presented in the following table.

Modeled SO2 Emissions and Source Parameters for Verifying Compliance with One-Hour SO2 NAAQS

Source ID	Description	Q (g/s)	XUTM (m)	YUTM (m)	THT(m)	HS(m)	TS (K)	VS (m/s)	DS(m)
SLG101	Slag Granulator 1 Granulation Tank 1	8.920E-01	707043.4	3329502.2	5.0	75.00	363.20	3.05	3.91
SLG102	Slag Granulator 1 Granulation Tank 2	4.460E-01	707084.1	3329491.3	5.0	75.00	363.20	3.05	3.91
SLG107	Blast Furnace 1 Slag Pits	1.020E+00	707020.5	3329487.3	5.0	30.50	699.80	18.29	1.83
SLG402	Slag Mill Dryer Stack	3.000E-03	707530.8	3329276.6	5.0	20.00	350.00	15.24	0.58
COK102	Coke Battery 1 Coke Pushing	2.670E+00	706490.7	3330278.2	5.0	9.20	1298.20	5.00	6.02
COK111	Coke Battery 1 Flue Gas Desulfurization Stack -- Normal Op	3.795E+01	706736.9	3330161.4	5.0	65.00	373.20	20.00	4.35
COK202	Coke Battery 2 Coke Pushing	2.670E+00	706510.7	3330397.9	5.0	9.20	1298.20	5.00	6.02
COK211	Coke Battery 2 Flue Gas Desulfurization Stack	3.795E+01	706791.7	3330375.0	5.0	65.00	373.20	20.00	4.35
PCI101	PCI Mill Vent	7.660E-03	706930.1	3329719.3	5.0	20.00	350.00	20.00	1.44
SIN101	MEROS System Vent Stack	1.533E+01	706675.8	3329536.4	5.0	75.00	393.20	20.00	3.89
PWR101	Topgas Boiler No.1	2.620E+00	707289.6	3330231.3	5.0	75.00	463.70	20.00	3.38
PWR103	Topgas Boiler No.3	2.620E+00	707285.3	3330214.9	5.0	75.00	463.70	20.00	3.38
STV101	Blast Furnace 1 Hot Blast Stoves Common Stack	2.440E+00	707077.2	3329651.4	5.0	80.00	623.20	20.00	4.02
DRI106	DRI Unit #1 Upper Seal Gas Vent	2.730E-03	706347.7	3329091.3	5.0	65.00	298.20	0.04	5.50
DRI107	DRI Unit #1 Furnace Dust Collection	4.860E-04	706311.7	3329084.3	5.0	65.00	317.00	20.80	1.30
DRI108	DRI Unit #1 Reformer Main Stack	3.990E-01	706390.0	3329261.4	5.0	65.00	453.20	21.50	3.50
DRI109	ORI Unit #1 Package Boiler Flue Stack	1.130E-02	706400.8	3329276.4	5.0	65.00	424.30	26.00	1.30
DRI110	ORI Unit #1 Hot Flare	1.230E-05	706320.4	3329085.3	5.0	65.00	1273.00	20.00	1.11
DRI111	ORI Unit #1 Acid Gas Absorption Vent	7.330E-02	706461.1	3329245.8	5.0	29.90	473.20	28.96	1.00
DRI112	ORI Unit #1 Product Storage Silo Dust Collection	9.940E-03	706292.3	3328857.9	5.0	65.00	317.00	22.30	1.34
DRI206	ORI Unit #2 Upper Seal Gas Vent	2.730E-03	706559.4	3329038.5	5.0	65.00	298.20	0.04	5.50
DRI207	ORI Unit #2 Furnace Dust Collection	4.860E-04	706523.5	3329031.5	5.0	65.00	317.00	20.80	1.30
DRI208	DRI Unit #2 Reformer Main Flue Stack	3.990E-01	706601.7	3329208.6	5.0	65.00	453.20	21.50	3.50
DRI209	ORI Unit #2 Package Boiler Flue Stack	1.130E-02	706612.5	3329223.6	5.0	65.00	424.30	26.00	1.30
DRI210	DRI Unit #2 Hot Flare	1.230E-05	706532.2	3329032.5	5.0	65.00	1273.00	20.00	1.11
DRI211	DRI Unit #2 Acid Gas Absorption Vent	7.330E-02	706672.9	3329193.0	5.0	29.90	473.20	28.96	1.00

DRI212	ORI Unit #2 Storage Silo Dust Collection	9.940E-03	706504.0	3328805.1	5.0	65.00	317.00	22.30	1.34
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It is important to note that compared to the pig iron plant permit modeling, Nucor revised some of the source parameters for the pig iron emissions at their facility. It appears that Nucor increased stack heights and plume rise inputs in an effort to decrease modeled one-hour NO₂ impacts, including the following changes:

- SLG107 (Blast furnace 1 slag pits): Stack height increased from 10.0 meters to 30.5 meters; Exit velocity increased from 6.01 meters/second to 18.29 meters/second; Stack diameter increased from 1.0 meter to 1.83 meters.
- PWR101 (Top gas boiler No.1): Stack height increased from 65.0 meters to 75.0 meters.
- PWR103 (Top gas boiler No.3): Stack height increased from 65.0 meters to 75.0 meters.
- STV101 (Blast Furnace 1 Hot Blast Stoves Common Stack): Stack height increased from 65.0 meters to 80.0 meters.
- COK102: (Coke Battery 1 Coke Pushing): Exit velocity increased from 1.00 meter/second to 5.00 meters/second.
- COK202: (Coke Battery 2 Coke Pushing): Exit velocity increased from 1.00 meter/second to 5.00 meters/second.

Of particular interest is the coke battery pushing emissions, which are modeled as sources COK102 and COK202. In the pig iron permit application; Nucor modeled these emissions with an exit velocity of 1.0 meter/second, but modeled these emissions with an exit velocity of 5.0 meters/second in their one-hour NO₂ NAAQS analysis for the combined emissions from pig iron and DRI facility components. Nucor failed to provide any justification for increasing the coke battery pushing exit Velocity, other than changing the value on the emission inventory questionnaire for these sources. In addition, Nucor's PM₁₀ and PM_{2.5} modeling of sources COK102 and COK202 used an exit velocity of 1.0 meter/second, even though these analyses were performed in October and November, 2010.

As discussed below, the undocumented change to COK102 and COK202 exit velocities has a substantial impact on modeled SO₂ concentrations. Furthermore, COK102 and COK202 coke pushing emissions are not stacks, and should not be modeled as such. Emissions from COK102 and COK202 are not collected into any device, nor are they controlled in any way whatsoever. Therefore, these sources are appropriately modeled as fugitive sources with plume rise from only buoyancy-induced conditions.

D. One-Hour SO₂ Modeling Results

To assess compliance with the one-hour SO₂ NAAQS, we modeled Nucor's pig iron/DRI coke pushing emissions with several different combinations of COK102 and COK202 source parameters. We also modeled these various scenarios with both 2001 - 2005 Baton Rouge Capitol Airport meteorological data and hybrid 2005 - 2008 data from LDEQ's Baker meteorological monitoring site. Most of the modeling scenarios described below are based on Nucor's normal operating emissions. For several instances, we also assessed Nucor's maintenance case 1A SO₂ emissions, which significantly increases modeled one-hour SO₂ impacts.

In summary, Nucor's aggregated pig iron/DRI emissions, when added to background SO₂ concentrations, will violate the one-hour SO₂ NAAQS with every conceivable combination of coke pushing release parameters and meteorological data. It should also be emphasized that these one-hour SO₂ NAAQS violations will occur solely due to emissions from Nucor's aggregate pig iron/DRI facility. Other NAAQS-consuming sources in the area are not included in these modeling analyses. Our results are discussed below.

Scenario 1:

- Aggregate pig iron/DRI SO₂ emissions;
- Baton Rouge Capitol Airport meteorological data, 2001 - 2005;
- Normal operating emissions;
- COK102 and COK202 modeled with 5.0 meters/second exit velocity.

This scenario uses the meteorological data Nucor prepared for their permit application modeling, as well as their undocumented coke pushing “stack” exit velocities of 5.0 meters/second. These inputs will lead to an under-prediction bias in modeled impacts, since the meteorological data lacks all wind speeds less than 1.5 meters/second and the exit velocities will artificially over-state plume rise.

For this scenario, Nucor's emissions result in a 44.20 µg/m³ five-year average fourth-highest daily maximum one-hour SO₂ concentration. When added to the background concentration (167 µg/m³), the total one-hour SO₂ concentration is 211.2 µg/m³. This is a violation of the one-hour SO₂ NAAQS. These results are summarized in the following table.

Nucor's H4H Conc. (µg/m ³)	Background H4H Conc. (µg/m ³)	Total H4H Conc. (µg/m ³)	One-Hour SO ₂ NAAQS (µg/m ³)	XUTM (m)	YUTM (m)
44.20	167.00	211.20	196.50	705556.0	3330743.6

Scenario 2:

- Aggregate pig iron/DRI SO₂ emissions;
- LDEQ's Baker wind speed and temperature data, 2005 - 2008;
- Normal operating emissions;
- COK102 and COK202 modeled with 5.0 meters/second exit velocity.

This scenario uses four years of AERMOD-ready meteorological data we prepared for our review of Nucor's permit application modeling. It also uses Nucor's undocumented coke pushing “stack” exit velocities of 5.0 meters/second. These exit velocity inputs will lead to an under-prediction bias in modeled impacts, due to artificially over-stated plume rise.

For this scenario, Nucor's emissions result in a 64.00 µg/m³ four-year average fourth-highest daily maximum one-hour SO₂ concentration. When added to the background concentration (167 µg/m³), the total one-hour SO₂ concentration is 231.0 µg/m³. This is a violation of the one-hour SO₂ NAAQS. These results are summarized in the following table.

Nucor's H4H Conc. (µg/m ³)	Background H4H Conc. (µg/m ³)	Total H4H Conc. (µg/m ³)	One-Hour SO ₂ NAAQS (µg/m ³)	XUTM (m)	YUTM (m)
64.00	167.00	231.00	196.50	707352.3	3328010.6

Scenario 3:

- Aggregate pig iron/DRI SO₂ emissions;
- Baton Rouge Capitol Airport meteorological data, 2001 -20,05;

- Maintenance Case 1A operating emissions (Coke Battery 1 flue gas desulfurization stack SO₂ emissions increased from 37.95 g/s to 114.69 g/s);
- COK102 and COK202 modeled with 5.0 meters/second exit velocity.

This maintenance case 1A scenario uses the meteorological data Nucor prepared for their permit application modeling, as well as their undocumented coke pushing “stack” exit velocities of 5.0 meters/second. These inputs will lead to an under-prediction bias in modeled impacts, since the meteorological data lacks all wind speeds less than 1.5 meters/second and the exit velocities will artificially over-state plume rise.

For this scenario, Nucor's emissions result in a 82.32 µg/m³ five-year average fourth-highest daily maximum one-hour SO₂ concentration. When added to the background concentration (167 µg/m³), the total one-hour SO₂ concentration is 249.32 µg/m³. This is a violation of the one-hour SO₂ NAAQS. These results are summarized in the following table.

Nucor's H4H Conc. (µg/m ³)	Background H4H Conc. (µg/m ³)	Total H4H Conc. (µg/m ³)	One-Hour SO ₂ NAAQS (µg/m ³)	XUTM (m)	YUTM (m)
82.32	167.00	249.32	196.50	705531.5	3330647.3

Scenario 4:

- Aggregate pig iron/DRI SO₂ emissions;
- LDEQ's Baker wind speed and temperature data, 2005 - 2008;
- Maintenance Case 1A operating emissions (Coke Battery 1 flue gas desulfurization stack SO₂ emissions increased from 37.95 g/s to 114.69 g/s);
- COK102 and COK202 modeled with 5.0 meters/second exit velocity.

This maintenance case 1A scenario uses four years of AERMOD-ready meteorological data we prepared for our review of Nucor's permit application modeling. It also uses Nucor's undocumented coke pushing “stack” exit velocities of 5.0 meters/second. These exit velocity inputs will lead to an under-prediction bias in modeled impacts, due to artificially over-stated plume rise.

For this scenario, Nucor's emissions result in a 113.15 µg/m³ four-year average fourth-highest daily maximum one-hour SO₂ concentration. When added to the background concentration (167 µg/m³), the total one-hour SO₂ concentration is 280.15 µg/m³. This is a violation of the one-hour SO₂ NAAQS. These results are summarized in the following table.

Nucor's H4H Conc. (µg/m ³)	Background H4H Conc. (µg/m ³)	Total H4H Conc. (µg/m ³)	One-Hour SO ₂ NAAQS (µg/m ³)	XUTM (m)	YUTM (m)
113.15	167.00	280.15	196.50	707282.5	3327939.5

Scenario 5:

- Aggregate pig iron/DRI SO₂ emissions;
- Baton Rouge Capitol Airport meteorological data, 2001 - 2005;
- Normal operating emissions;
- COK102 and COK202 modeled with 1.0 meter/second exit velocity.

This scenario uses the meteorological data Nucor prepared for their permit application modeling, as well as their unrealistic coke pushing "stack" exit velocities of 1.0 meter/second. These inputs will lead to an under-prediction bias in modeled impacts, since the meteorological data lacks all wind speeds less than 1.5 meters/second and the exit velocities will artificially over-state momentum plume rise.

For this scenario, Nucor's emissions result in a 100.18 $\mu\text{g}/\text{m}^3$ five-year average fourth-highest daily maximum one-hour SO_2 concentration. When added to the background concentration (167 $\mu\text{g}/\text{m}^3$), the total one-hour SO_2 concentration is 267.18 $\mu\text{g}/\text{m}^3$. This is a violation of the one-hour SO_2 NAAQS. These results are summarized in the following table.

Nucor's H4H Conc. ($\mu\text{g}/\text{m}^3$)	Background H4H Conc. ($\mu\text{g}/\text{m}^3$)	Total H4H Conc. ($\mu\text{g}/\text{m}^3$)	One-Hour SO_2 NAAQS ($\mu\text{g}/\text{m}^3$)	XUTM (m)	YUTM (m)
100.18	167.00	267.18	196.50	705678.5	3331225.3

Scenario 6:

- Aggregate pig iron/DRI SO_2 emissions;
- LDEQ's Baker wind speed and temperature data, 2005 - 2008;
- Normal operating emissions;
- COK102 and COK202 modeled with 1.0 meter/second exit velocity.

This scenario uses four years of AERMOD-ready meteorological data we prepared for our review of Nucor's permit application modeling. It also uses Nucor's unrealistic coke pushing "stack" exit velocities of 1.0 meter/second. These exit velocity inputs will lead to an under-prediction bias in modeled impacts, due to artificially over-stated momentum plume rise.

For this scenario, Nucor's emissions result in a 103.40 $\mu\text{g}/\text{m}^3$ four-year average fourth-highest daily maximum one-hour SO_2 concentration. When added to the background concentration (167 $\mu\text{g}/\text{m}^3$), the total one-hour SO_2 concentration is 270.40 $\mu\text{g}/\text{m}^3$. This is a violation of the one-hour SO_2 NAAQS. These results are summarized in the following table.

Nucor's H4H Conc. ($\mu\text{g}/\text{m}^3$)	Background H4H Conc. ($\mu\text{g}/\text{m}^3$)	Total H4H Conc. ($\mu\text{g}/\text{m}^3$)	One-Hour SO_2 NAAQS ($\mu\text{g}/\text{m}^3$)	XUTM (m)	YUTM (m)
103.40	167.00	270.40	196.50	705678.5	3331225.3

Scenario 7:

- Aggregate pig iron/DRI SO_2 emissions;
- Baton Rouge Capitol Airport meteorological data, 2001 - 2005;
- Maintenance Case 1A operating emissions (Coke Battery 1 flue gas desulfurization stack SO_2 emissions increased from 37.95 g/s to 114.69 g/s);
- COK102 and COK202 modeled with 1.0 meter/second exit velocity.

This maintenance case 1A scenario uses the meteorological data Nucor prepared for their permit application modeling, as well as their unrealistic coke pushing "stack" exit velocities of 1.0 meter/second. These inputs will lead to an under-prediction bias in modeled impacts, since the meteorological data lacks all wind speeds less than 1.5

meters/second and the exit velocities will artificially over-state momentum plume rise.

For this scenario, Nucor's emissions result in a 100.37 $\mu\text{g}/\text{m}^3$ five-year average fourth-highest daily maximum one-hour SO_2 concentration. When added to the background concentration (167 $\mu\text{g}/\text{m}^3$), the total one-hour SO_2 concentration is 267.37 $\mu\text{g}/\text{m}^3$. This is a violation of the one-hour SO_2 NAAQS. These results are summarized in the following table.

Nucor's H4H Conc. ($\mu\text{g}/\text{m}^3$)	Background H4H Conc. ($\mu\text{g}/\text{m}^3$)	Total Conc. ($\mu\text{g}/\text{m}^3$)	H4H	One-Hour SO_2 NAAQS ($\mu\text{g}/\text{m}^3$)	XUTM (m)	YUTM (m)
100.37	167.00	267.37		196.50	705678.2	3331225.3

Scenario 8:

- Aggregate pig iron/DRI SO_2 emissions;
- LDEQ's Baker wind speed and temperature data, 2005 - 2008;
- Maintenance Case 1A operating emissions (Coke Battery 1 flue gas desulfurization stack SO_2 emissions increased from 37.95 g/s to 114.69 g/s);
- COK102 and COK202 modeled with 1.0 meter/second exit velocity.

This maintenance case 1A scenario uses four years of AERMOD-ready meteorological data we prepared for our review of Nucor's permit application modeling. It also uses Nucor's unrealistic coke pushing "stack" exit velocities of 1.0 meter/second. These exit velocity inputs will lead to an under-prediction bias in modeled impacts, due to artificially over-stated momentum plume rise.

For this scenario, Nucor's emissions result in a 116.74I $\mu\text{g}/\text{m}^3$ four-year average fourth-highest daily maximum one-hour SO_2 concentration. When added to the background concentration (167 $\mu\text{g}/\text{m}^3$), the total one-hour SO_2 concentration is 283.74 $\mu\text{g}/\text{m}^3$. This is a violation of the one-hour SO_2 NAAQS. These results are summarized in the following table.

Nucor's H4H Conc. ($\mu\text{g}/\text{m}^3$)	Background H4H Conc. ($\mu\text{g}/\text{m}^3$)	Total Conc. ($\mu\text{g}/\text{m}^3$)	H4H	One-Hour SO_2 NAAQS ($\mu\text{g}/\text{m}^3$)	XUTM (m)	YUTM (m)
116.74	167.00	283.74		196.50	707492.0	3328152.8

Scenario 9:

- Aggregate pig iron/DRI SO_2 emissions;
- Baton Rouge Capitol Airport meteorological data, 2001 - 2005;
- Normal operating emissions;
- COK102 and COK202 modeled as an AREAPOLY source.

Nucor's proposed project includes two coke oven batteries. These batteries, which are to be placed at the northern end of the project site, are approximately 800 meters in length and about 50 meters wide. Discussions on the coke oven dimensions are presented in the permit application. We also determined the length, width, and height of the proposed coke ovens from the building profile input program (BPIP) files obtained from LDEQ. The height of the proposed coke oven batteries is 6 meters (20 feet tall).

Nucor's coke batteries are significant emission sources of SO_2 , particulate matter, and

hazardous air pollutants. The manner in which the coke oven emissions are modeled is extremely important, yet Nucor models these sources as very simplistic point sources. The coke pushing source parameters modeled by Nucor do not depict actual emission releases from the coke ovens and they will under-predict air impacts. This is because Nucor used emission release parameters that likely over-state plume rise.

Each of Nucor's coke oven batteries includes a series of 140 connected batteries, which will include coal charging and coke pushing activities that take 54 hours per cycle. Based on this information, we calculate that every 23 minutes one oven per battery is charged or pushed. In other words, charging and pushing emissions will occur along the length of the entire coke batteries, yet only one oven per battery will have charging or pushing air emissions at any given time.

Nucor has failed to provide sufficient details on the sequence of coal charging and coke pushing to allow a complete analysis of how the emissions are released from each of the coke oven batteries. The sequence of charging and pushing will be influenced by the length of the operational cycle (54 hours), as well as the traffic management aspects of the mobile charging and quenching cars. Nevertheless, the temporal and spatial separation of coke pushing operations along each battery will maximize ambient air entrainment and minimize plume rise. USEPA, Risk Assessment Document for Coke Oven MACT Residual Risk, December 22, 2003, p. 30. For this reason, a vertically-mixed area polygon source approach to modeling the coke oven emissions is more appropriate than the single point method used by Nucor.

Since Nucor's coke pushing fugitive emissions occur intermittently over a rather large area, we remodeled these releases as an area-polygon emission source. LDEQ, Air Quality Modeling Procedures, August 2006, p. 5-9. For this analysis, we created a polygon area source using the AREAPOLY source type provided for within AERMOD. The AREAPOLY source is used to specify an area source as a polygon of up to 20 sides. See USEPA, User's Guide for the AMS/EPA Regulatory Air Model - AERMOD, EPA-454/B-03-001, September 2004, p. 3-16.

For the coke oven battery AREAPOLY source, the following AERMOD inputs are required:

- A source identifier number or name;
- Source Location X (Easting) coordinate;
- Source Location Y (Northing) coordinate;
- Source base elevation (meters above sea level);
- Emission flux ($\text{g}/(\text{s}\cdot\text{m}^2)$);
- Release height of the area source (meters);
- Number of polygon vertices;
- X and Y coordinates for each polygon vertex;
- Initial vertical dispersion of the area source plume (meters).

The area-polygon emission source we developed covers Nucor's two coke batteries and the area between the batteries. This provides for a representation of the fugitive emissions that would occur from all parts of the coke oven batteries, rather than the single points modeled by Nucor. Furthermore, including the area between the batteries provides for additional lateral emission releases that occur with charging and pushing operations. The coke oven area-polygon fugitive emission source covers 36.97 acres, or 149,600 square meters.

We modeled the area-polygon emission source with a release height of 6 meters, which is the top of the coke oven battery height. We chose this level to provide for increased plume height that could result from the buoyant nature of the emissions. We calculated an initial vertical dispersion parameter using a total release profile of 12 meters (twice the battery height) and dividing by 2.15 (resulting in 5.581 meters). We believe this is a reasonable representation of initial vertical dispersion from the coke ovens. Building downwash is not an option in modeling area sources; however, the initial vertical dispersion parameter inherent in this source type will provide additional mixing. In essence, the coke pushing emissions will be mixed throughout the 12 meter vertical layer and over the entire extent of the 36.97 acre area source.

We calculated the emission (flux) rate for the coke oven area-polygon source by combining the emissions from coke pushing (sources COKI02 and COK202), and then dividing the summed emissions by the AREAPOLY source area (149,600 square meters). Our calculated SO₂ emission (flux) rate is 3.570E-05 g/(s-m²).

Although this scenario uses a much more realistic method to account for the way coke pushing emissions are released to the atmosphere, it still uses meteorological data Nucor prepared for their permit application modeling. The Baton Rouge Capitol Airport data will lead to an under-prediction bias in modeled impacts, since the meteorological data lacks all wind speeds less than 1.5 meters/second.

For this scenario, Nucor's emissions result in a 1418.07 µg/m³ five-year average fourth-highest daily maximum one-hour SO₂ concentration. When added to the background concentration (167 µg/m³), the total one-hour SO₂ concentration is 1585.07 µg/m³. This is a violation of the one-hour SO₂ NAAQS, with or without adding the background concentration. These results are summarized in the following table.

Nucor's H4H Conc. (µg/m ³)	Background H4H Conc. (µg/m ³)	Total Conc. (µg/m ³)	H4H One-Hour SO ₂ NAAQS (µg/m ³)	XUTM (m)	YUTM (m)
1418.07	167.00	1585.07	196.50	705507.0	3330550.9

Scenario 10:

- Aggregate pig iron/DRI SO₂ emissions;
- LDEQ's Baker wind speed and temperature data, 2005 - 2008;
- Normal operating emissions;
- COKI02 and COK202 modeled as an AREAPOLY source.

This scenario uses the same AREAPOLY source characteristics described in Scenario 5, including the much more realistic method to account for the way coke pushing emissions are released to the atmosphere. This scenario also uses the much more appropriate hybrid Baker meteorological data - a data set that is not sanitized of all low wind speeds less than 1.5 meters/second.

For this scenario, Nucor's emissions result in a 3303.97 µg/m³ four-year average fourth-highest daily maximum one-hour SO₂ concentration. When added to the background concentration (167 µg/m³), the total one-hour SO₂ concentration is 3470.97 µg/m³. This is a violation of the one-hour SO₂ NAAQS, with or without adding the background concentration. These results are summarized in the following table.

Nucor's	Background	Total	H4H	One-Hour	XUTM (m)	YUTM (m)
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H4H Conc. (µg/m3)	H4H Conc. (µg/m3)	Conc. (µg/m3)	SO2 NAAQS (µg/m3)		
3303.97	167.00	3470.97	196.50	705488.9	3330626.2

Scenario 11:

- Aggregate pig iron/DRI SO₂ emissions;
- LDEQ's Baker wind speed and temperature data, 2005 - 2008;
- Normal operating emissions;
- COK102 and COK202 modeled using LDEQ's pseudopoint source method.

As a further sensitivity analysis, we also modeled Nucor's coke pushing fugitive SO₂ emissions as a pseudopoint source. LDEQ's modeling guidelines discuss fugitive release parameters for emission sources such as Nucor's proposed coal charging activities:

LDEQ requires fugitive emissions to be modeled as pseudopoint (i.e., LDEQ default parameters), area, or area-polygon emission sources. *See* LDEQ, Air Quality Modeling Procedures, August 2006, p. 5-9.

LDEQ's default parameters are as follows:

For missing or unavailable data, LDEQ requires the following source parameters or documentation for use of parameters from comparable equipment:

- Default height is 3.28-feet (1-meter);
- Default exit temperature is -459.67 °F (0 °K);
- Default exit velocity is 0.00328-feet-per-second (0.001-meters-per second); and
- Default diameter is 3.28-feet (or 1-meter). *See* LDEQ, Air Quality Modeling Procedures, August 2006, p. 5-9.

Nucor incorrectly modeled the fugitive emissions from coke pushing as two separate point sources that in no way represent the emission releases from coke pushing (sources COK102 and COK202). Nucor's coke pushing emissions were modeled as two point sources (one for each battery), with the following stack parameters:

- Stack height: 9.2 meters
- Stack gas exit velocity: 1.00 meter/second (or 5.00 meters/second for particulate matter runs)
- Stack diameter: 6.02 meters
- Stack gas temperature: 1298.2 Kelvin. *Id.*, Table 6-4.

The coke pushing releases are likely to occur at a level of roughly ~ of the oven battery building height, or about three meters above the ground. This is consistent with Nucor's proposed flat car pushing method. The exit temperature for coke pushing (1298.2 K) seems to be over-stated, and Nucor has not provided any documentation or support for this value. The stack gas exit velocity and diameter used by Nucor, however, are not representative of coke pushing fugitive emissions and cannot be modeled with the parameters they have chosen. For these parameters, LDEQ's default values of 0.001 meter/second for exit velocity and 1.0 meter for diameter should be used.

In this sensitivity analysis we remodeled the coke pushing emissions with the following parameters:

- Stack height: 3.0 meters
- Stack gas exit velocity: 0.001 meter/second (LDEQ fugitive emission default)

- Stack diameter: 1.00 meter (LDEQ fugitive emission default)
- Stack gas temperature: 1298.2 Kelvin

This scenario also uses the much more appropriate hybrid Baker meteorological data – a data set that is not sanitized of all low wind speeds less than 1.5 meters/second. .
For this modeling scenario, Nucor's emissions result in a 7211.9 $\mu\text{g}/\text{m}^3$ four-year average fourth-highest daily maximum one-hour SO_2 concentration. When added to the background concentration (167 $\mu\text{g}/\text{m}^3$), the total one-hour SO_2 concentration is 7378.9 $\mu\text{g}/\text{m}^3$. This is a violation of the one-hour SO_2 NAAQS, with or without adding the background concentration. These results are summarized in the following table.

Nucor's H4H Conc. ($\mu\text{g}/\text{m}^3$)	Background H4H Conc. ($\mu\text{g}/\text{m}^3$)	Total H4H Conc. ($\mu\text{g}/\text{m}^3$)	One-Hour SO_2 NAAQS ($\mu\text{g}/\text{m}^3$)	XUTM (m)	YUTM (m)
7211.90	167.00	7378.90	196.50	706238.7	3328548.1

In sum, we modeled the aggregate SO_2 emissions from Nucor's pig iron/DRI plant - a task that Nucor failed to perform. Our modeling analyses, which include 11 different coke oven release and meteorological data configurations, all show that Nucor's SO_2 emissions will cause or contribute to violations of the one-hour SO_2 NAAQS. The DRI PSD permit and modified pig iron Part 70 permit must be denied because of these modeled SO_2 violations.

LDEQ Response to Comment No. VII.44

Please see LDEQ Response to Comment No. V.A.2 for LDEQ's rationale for considering the DRI facility and the pig iron plant to be separate projects. On this basis, modeling review was not aggregated. The applicant submitted the pig iron facility permit modification as a minor modification with emissions of SO_2 greatly reduced. The PSD permit for the pig iron facility, PSD-LA-740, passed scrutiny of SO_2 NAAQS standards before it was approved. Under minor modification procedures, further review of NAAQS standards is not performed. Impact of SO_2 emissions from the proposed DRI plant will be below the significant monitoring concentrations. Refined modeling is not required.

The DRI Facility is considered a separate project under PSD permitting regulations; as such modeling for the 1-hour SO_2 standard was performed for the DRI facility alone. The highest modeled concentration for the DRI Facility is 2.6 $\mu\text{g}/\text{m}^3$, which is below EPA's interim significance level of 8 $\mu\text{g}/\text{m}^3$. The results indicate that the DRI Facility is an insignificant source of SO_2 emissions, and therefore cumulative modeling is not required.

Aggregate modeling of the DRI and Pig Iron facilities is not required under PSD permitting regulations, as they are considered separate projects. Modeling of SO_2 emissions for the 1-hour averaging period was not required for the Pig Iron Facility as the permit was issued prior to the final standard's promulgation in the Federal Register. The modification application is a minor modification of the permit in which the emissions of SO_2 decrease from the previously permitted levels; therefore modeling of the Pig Iron Facility emissions is not required.

Comment No. VII.45

The allowable emission rates for 24-hour fugitive PM_{10} and $\text{PM}_{2.5}$ emissions from unpaved and paved roads are calculated using an inappropriate rainfall correction. Nucor calculated separate fugitive PM_{10} and $\text{PM}_{2.5}$ emission rates for vehicle travel on onsite

unpaved and paved roads. In these calculations, Nucor used inappropriate rainfall correction factors for assessing 24-hour PM_{10} and $PM_{2.5}$ emission rates from both unpaved and paved roads.

A. Unpaved Roads

For unpaved roads, Nucor calculated only annual-average PM_{10} and $PM_{2.5}$ emissions, and used an emission reduction factor based on the number of days of rain per year. This strategy is not applicable to short-term emission rate calculations where rainfall during the averaging period should not be considered. *See* USEPA, Office of Air Quality Planning and Standards, AP-42, Section 13.2.2, Unpaved Roads, November 2006, pp. 13.2.2-6 - 13.2.2-7. The USEPA emission rate calculations for unpaved roads only provide rainfall corrections to annual-average emission rates. This is done by applying an adjustment factor of $((365-P)/365)$ to the emission calculations (P is the number of days of rain per year). Nucor should have calculated two unpaved road PM emission rate values - one for 24-hour emissions and one for annual-average emissions.

For example, it may not rain for many days in a row, thus rainfall will not be a mitigating factor when calculating 24-hour PM_{10} emission rates during that dry period. In essence, Nucor inappropriately applied an annual-average rainfall-reduced PM_{10} and $PM_{2.5}$ emission rate calculation to 24-hour PM_{10} and $PM_{2.5}$ emissions.

Nucor applied a correction factor of $((365-110)/365)$ to their 24-hour PM_{10} emissions, where 110 is the number of days per year with rainfall greater than or equal to 0.01 inch. Removing this incorrect emission reduction to 24-hour PM_{10} emissions increases the calculated emission by a factor of 1.431 ($365/255$).

B. Paved Roads

Nucor also used an inappropriate rainfall correction factor for calculating 24-hour PM_{10} and $PM_{2.5}$ emission rates from paved roads (just as they did for unpaved roads). Nucor calculated only annual-average paved road PM_{10} and $PM_{2.5}$ emissions, and used an emission reduction factor based on the number of days of rain per year. For paved roads, Nucor inappropriately applied annual-average rainfall-reduced PM_{10} and $PM_{2.5}$ emission rate calculations to 24-hour paved road PM_{10} and $PM_{2.5}$ emissions.

Nucor applied a correction factor of $(1-(110/365))$ to their 24-hour paved road PM_{10} and $PM_{2.5}$ emissions, where 110 is the number of days per year with rainfall greater than or equal to 0.01 inch. *Id* First, this isn't even the correct rainfall emission reduction factor for annual-average paved road fugitive dust emissions. The correct factor is $(1-110/(4*365))$. *See* USEPA, Office of Air Quality Planning and Standards, AP-42, Section 13.2.1, Paved Roads, November 2006, pp. 13.2.1-6. Second, this factor should not apply at all to short-term emission rates where rainfall is zero during the averaging period. *Id*, 13.2.1-6 - 13.2.1-7. Removing this incorrect emission reduction to 24-hour paved road PM_{10} and $PM_{2.5}$ emissions increases the calculated emission by a factor of 1.431 ($365/255$).

LDEQ Response to Comment No. VII.45

Short-term emission calculations provided by the applicant apply a factor of 1.5 when determining one-hour maximum emissions from both paved and unpaved roads. LDEQ determined that this factor was conservative, an opinion which is supported by the commenter's conclusion that the factor should be 1.431. Both paved and unpaved roads at the facility are required to comply with

the most recently approved version of the Nucor Steel Louisiana Dust Management Plan, which includes frequent watering of unpaved roads to limit the generation of dust during dry conditions.

The commenter is incorrect in stating that Nucor modeled average annual emissions for the paved and unpaved roads using a rainfall correction factor of 110 days per year, although average annual emissions for the permit were calculated on this basis for both sources. Nucor separately calculated maximum hourly emission rates for these sources and used these emission rates for the purposes of the model.

LDEQ agrees that the commenter's approach of using zero days of rainfall per year would provide an appropriate value for maximum daily modeling. Also, the factor of 1.43 is correct when comparing between these two different calculations. However, applying this factor to the average annual emission rate presented by Nucor for both paved and unpaved roads results in an emission rate less than respective maximum emission rates provided and used for PM₁₀ modeling. Nucor used a factor of 50% over the average annual emission rate (i.e., a factor of 1.5) to predict increased emissions for the maximum emission rate, which was used in the modeling. In this respect, the emissions, and thus the modeling results, are conservative.

Comment No. VII.46

The allowable emission rates for fugitive PM₁₀ and PM_{2.5} emissions from unpaved and paved roads are based on an assumption of 90% road dust control efficiency, which is overstated, unrealistic and not supported by the literature. LDEQ requires Nucor to reduce fugitive dust emissions from paved and unpaved roads:

BACT for road dust is to pave roadways where practicable including areas where the extra heavy vehicles (greater than 50 tons in weight) will not cause damage to paving. Watering and sweeping will be used on paved roads along with reduced speed limits of less than or equal to 15 mph. Unpaved roads shall utilize water spray or dust suppression chemicals to reduce emissions. Additionally, reduced speed limits of less than or equal to 15 mph will be enforced on all unpaved roadways.

Nucor credited a 90% emission reduction to fugitive PM₁₀ and PM_{2.5} emissions to both paved and unpaved roads by applying the above controls. These assumed control efficiencies are overstated, and peak-daily emissions will be higher than that modeled by Nucor.

A. Unpaved Roads

For unpaved roads, the 90% assumed dust control efficiency is almost certainly unachievable, even if Nucor continuously applies water and chemical suppressants. Furthermore, continuous watering is impractical or impossible. In any event, continuous watering is not required by the permit or enforceable as a practical matter and, therefore, the claimed 90% control cannot represent the worst-case conditions that must be assumed for modeling.

In addition, the type of suppressants to be used on unpaved roads is not required as a permit condition by LDEQ. Thus, the reliability of the suppressants in reducing fugitive PM₁₀ and PM_{2.5} emissions from vehicle travel on unpaved roads is completely unknown. Furthermore, the proposed permit is silent on the required frequency of watering and for applying the unspecified dust suppressants. In other words, there is no support whatsoever for assuming 90% control efficiency for unpaved road dust emissions.

Dust emissions from unpaved roads, as well as possible control approaches, have been widely studied. Using watering as a control technique will typically yield unpaved road dust control efficiencies on the order of 50%. Following are several references documenting this finding:

- USEPA reports 50% control for a water application intensity of about 0.2 gallon/yd²/hour, See USEPA, Control of Open Fugitive Dust Sources, EPA-450/3-88-008, September 1988, p. 5-10.
- The 50% figure is presented in Fugitive Emissions and Controls, which also lists 60 to 80% controls for non-water wetting agents. See Howard Hesketh and Frank Cross, Fugitive Emissions and Controls, Ann Arbor Science, 1983, p. 42.
- The South Coast Air Quality Management District suggests control efficiencies of 34 to 68% for watering of unpaved roads. See South Coast Air Quality Management District, CEQA Air Quality Handbook, April 1993, pp. 11-15.
- The WRAP Fugitive Dust Handbook lists control efficiencies of 10% to 74% for watering of unpaved roads. See Western Governor's Association, WRAP Fugitive Dust handbook, November 15, 2004, p. 3.

The control efficiency that can be achieved by watering or application of chemical suppressant depends upon the: (1) amount of water or suppressant applied per unit area of road surface; (2) time between applications; (3) traffic volume during period; and (4) prevailing meteorological conditions. Methods have been developed to determine the amount of water or suppressant and the application frequency required to achieve a given control efficiency. See C. Cowherd, G.E. Muleski, and J.S. Kinsey, Control of Open Fugitive Dust Sources, September 1988, Section 3.3. Nucor should be required to develop a fugitive dust control plan as part of its BACT analysis for haul roads. This plan should be circulated for public review as part of LDEQ's draft permit.

Furthermore, watering unpaved roads increases the amount of mud and dirt that is transported and deposited on adjacent paved roads. This would increase the PM₁₀ emissions from adjacent roads, compared to those estimated by Nucor. A recent study conducted in Kansas City found that PM₁₀ emissions from 1400 feet of trackout-affected roadway are equivalent to about 6 miles of roadway not affected by trackout. See Gregory E. Muleski, Chatten Cowherd, Jr. and John S. Kinsey, Particulate Emissions from Construction Activities, J. Air & Waste Manage. Assoc., v. 55, 2005, pp. 772-783. Nucor's haul road emissions should be revised to include trackout.

We recalculated onsite unpaved road dust fugitive PM₁₀ and PM_{2.5} emissions assuming 75% controls, which is most likely an over-estimation of achievable fugitive dust control on Nucor's unpaved roads. The correction from 90% assumed control efficiency to a more realistic 75% control increases the unpaved road dust fugitive PM₁₀ and PM_{2.5} emissions by a factor of 2.5.

B. Paved Roads

Nucor calculated and modeled fugitive PM₁₀ emissions from vehicle travel on onsite paved roads. These emissions were combined with unpaved road emissions, and modeled as discrete volume sources placed along certain proposed roadways. Paved road PM₁₀ and PM_{2.5} emissions were calculated by ERM in the pig iron PSD permit application, and they assumed 90% dust control efficiency from sweeping. Assuming that sweeping will provide 90% control efficiency is simply unrealistic, and is inconsistent with LDEQ's specific conditions requiring watering and sweeping. It is important to note that 90% controls were consistently assumed by the Applicant, even though the stated control

method changed from sweeping to sweeping and watering.

The 90% assumed dust control efficiency for paved roads is almost certainly unachievable. Since the roads are already paved, there is relatively less dust to control, thus making high control efficiencies difficult to achieve. Typical paved road dust control efficiencies will be on the order of 50%, unless the applicant sweeps and waters non-stop or does so after only a few vehicles have used the roads. *See* USEP A, Control of Open Fugitive Dust Sources, EPA-450/3-88-008, September 1988, pp. 2-6,7. This is impractical or impossible, rendering 90% dust control efficiency unattainable. Furthermore, the proposed permit is silent on the required frequency of sweeping and watering. In other words, there is no support whatsoever for assuming 90% control efficiency for paved road dust emissions.

Aggressive sweeping programs with efficient vacuum units achieve only 16% PM₁₀ control. *See* Western Governor's Association, WRAP Fugitive Dust handbook, November 15, 2004, Table 5-5. Studies done in Minnesota and elsewhere indicate that daily road sweeping, vacuuming and washing (weather permitting) plus speed limit controls (5 mph) are required to achieve 50% control of fugitive PM₁₀ emissions. *See* Minnesota Pollution Control Agency, Air Emission Permit No. 13700028-005, July 11, 2005.

Also, the control efficiency achieved by paving depends upon how frequently the pavement is cleaned after paving and whether curbing is installed. Trucks can veer onto unpaved shoulders or suspended roadside dust unless curbing is installed. *See* USEPA, Office of Air Quality Planning and Standards, AP-42, Section 13.2.1, Paved Roads, November 2006, pp. 13.2.1-10. Curbing is not required by the draft permit or discussed in the files we reviewed. Thus, additional emissions from roadside dust should be included in estimated emissions from paved haul roads or a lower control efficiency for paving assumed.

Paved roads in the Nucor facility will no doubt be adjacent to unpaved travel areas, including the storage piles and unpaved roads. Thus, spillage and carryout from these unpaved areas can reduce the effectiveness of controls on the paved area. This requires periodic housekeeping activities to cleanup any trackout, or a reduction in assumed control efficiencies and increases in controlled emissions.

We recalculated on site paved road dust fugitive PM₁₀ and PM_{2.5} emissions assuming 75% controls, which is most likely an over-estimation of achievable fugitive dust control on Nucor's paved roads. The correction from 90% assumed control efficiency to a more realistic 75% control increases the paved road dust fugitive PM₁₀ emissions by a factor of 2.5.

Combining the rainfall mitigation correction with the 2.5 increase from the more realistic 75% control efficiency will increase Nucor's unpaved road emissions by a total factor of 3.58 (2.5*1.431). These 24-hour PM₁₀ and PM_{2.5} emission rates are shown in the tables below.

Source Term (Modeled as Volume Sources and labeled as sources R1 through R18)	Nucor's PM ₁₀ Emissions per Volume Source (g/s)	Corrected PM ₁₀ Emissions per Volume Source (g/s)
Road Traffic, Unpaved Roads	4.15E-02	1.48E-01

(18 Volume Sources)		
Source Term (Modeled as Volume Sources and labeled as sources R1 through R18)	Nucor's PM ₁₀ Emissions per Volume Source (g/s)	Corrected PM ₁₀ Emissions per Volume Source (g/s)
Road Traffic, Unpaved Roads (18 Volume Sources)	4.21E-03	1.506E-02

The PM10 and PM2.5 emission rates in the DRI and pig iron permits should be revised, and the corrected emission rates used for ambient air quality impact analyses.

LDEQ Response to Comment No. VII.46

We agree that 90% control is a high standard for the control of road dusts. LDEQ determined that the applicant presented innovative ideas for road watering, including the installation of permanent in-ground water spraying systems for maintaining water on plant roads automatically, which represents a significant improvement over conventional methods employing tank trucks fitted with water spray nozzles. The commenter's contention that maintaining continuous watering is "impractical or impossible" is supported only by documents which appear to base their conclusions on these conventional methods.

The commenter's assertion that the applicant still needs to "develop a fugitive dust control plan", and circulate that plan for public review is in error; such a plan entitled Nucor Steel Louisiana Dust Management Plan has been developed and available for review for a great deal of time, and in any event not less than 18 months. The applicant is required to comply with the most recently approved version of the Nucor Steel Louisiana Dust Management Plan. Paved roads must be maintained in a clean state through the application of road sweeping and watering activities, which has been determined as BACT. Trackout conditions described by the applicant would represent a violation of the approved Dust Management Plan and Title V permit.

The applicant submitted a Dust Management Plan for the facility, which addresses fugitive dust controls for roadways. In the plan, the applicant indicates that permanent road sprinkler systems will be installed to water roadways and other unpaved areas on a routine and automatic basis. LDEQ believes this automatic delivery approach is a significant enhancement to typical truck-borne road watering plans and assigning a higher control efficiency factor is appropriate.

The applicant submitted the Dust Management Plan as evidence that high control efficiencies would be achievable. Figure 13.2.2-2 (Watering control effectiveness for unpaved travel surfaces) of AP-42 Section 13.2.2 – Unpaved Roads clearly shows that with sufficient watering and chemical suppressants, a control level of 90% is achievable. Spillage control measures are addressed by the plan. Similarly, trackouts can be controlled through the implementation of frequent sweeping or installation of wheel washing stations at paving transition points, or both. As stated in the BACT determination, paved roads must be maintained free of mud, dirt, and other materials in order to remain an effective option for controlling fugitive dusts. The commenter's reference to a specific, low control efficiency assigned to sweeping paved roads in AP-42 could not be found. Instead the document states that control efficiencies are variable and depend upon local silt loading conditions.

Moreover, the permit is not reliant on published control efficiencies. Nucor's Dust Management Plan requires actual monitoring of dust during both the construction and operation of the facility with deposition gauges, portable monitors, and visual inspections. This plan also includes quantifiable action levels and prescribes corrective actions. LDEQ has determined these work

practice standards meet BACT for fugitive particulate emissions.

See also LDEQ Response to Comment No. VII. 45 for our response to the characterization of short-term fugitive emissions from plant roads.

Comment No. VII.47

PSD Permit No. PSD-LA-741 and Part 70 Permit No. 2560-00281-VI should be denied, because Nucor's PM₁₀ and PM_{2.5} emissions -- as corrected -- will cause PM₁₀ PSD increment violations, PM₁₀ NAAQS violations, and PM_{2.5} NAAQS violations.

In October, 2010, Nucor modeled PM₁₀ and PM_{2.5} emissions from the aggregate pig iron/DRI components of their facility. These modeling analyses purported to show no violations of the applicable PSD increments and NAAQS. Nucor's modeling, however, is based on incorrect emission calculations and flawed modeling methods. Correcting these inadequacies will result in significantly higher modeled impacts.

Nucor made the following errors in their PM₁₀ and PM_{2.5} emission calculations, which are then used as input to their air modeling analyses:

- Nucor calculated annual-average PM₁₀ and PM_{2.5} emissions from unpaved roads, using a yearly total of rain days per year. They then modeled both 24-hour and annual-average impacts using this annual-average emission rate. This results in an under-estimate of 24-hour PM₁₀ and PM_{2.5} emission rates.
- Nucor assumes an over-stated control efficiency of 90% for watering the unpaved roads.
- Nucor calculated annual-average PM₁₀ and PM_{2.5} emissions from paved roads, using a yearly total of rain days per year. They then modeled both 24-hour and annual-average impacts using this annual-average emission rate. This results in an under-estimate of 24-hour PM₁₀ and PM_{2.5} emission rates.
- Nucor assumes an over-stated control efficiency of 90% for watering the paved roads.
- Nucor under-estimated cooling tower PM₁₀ emissions by assuming that less than 15% of the drift is in the form of PM₁₀.
- Nucor under-estimates PM₁₀ and PM_{2.5} emissions from source DRI18 (DRI Barge loading dock) due to overestimated moisture content, underestimated wind speed, and the omission of a conveyor service factor from the calculations.
- Nucor under-estimates PM₁₀ and PM_{2.5} emissions from source DOC101 (Dock 1 Loading/Unloading Gantry Crane) due to overestimated moisture content.

We corrected Nucor's emission rate mistakes that are described above. Our corrections are discussed in comments specific to each emission source and can be found in other sections of this document. In addition, Nucor modeled a number of the pig iron/DRI PM₁₀ and PM_{2.5} emission sources in a manner that will further under-estimate ambient air impacts. Examples include:

- Nucor modeled the road emissions as 18 separate volume sources, which do not adequately cover the roads identified in their plot plans.
- Nucor failed to model any road emissions from the road nearest the Zen-Noh facility.
- Nucor combined the emissions from paved and unpaved roads and assigned them equally to the 18 volume sources they modeled. Paved and unpaved roads should be modeled separately.
- Nucor modeled PM₁₀ and PM_{2.5} emissions from COK101 and COK201 (coke oven coal charging) as "stack" emissions rather than the uncontrolled fugitive sources that

- they are. Nucor used an overly high stack height and over-stated volumetric flow input parameters in their modeling of coke oven coal charging.
- Nucor modeled PM₁₀ and PM_{2.5} emissions from COK102 and COK202 (coke oven coke pushing) as "stack" emissions rather than the uncontrolled fugitive sources that they are. Nucor used an overly high stack height and over-stated volumetric flow input parameters in their modeling of coke oven coke pushing.

Our modeling analyses of Nucor's PM₁₀ and PM_{2.5} emissions address only the emission corrections discussed above. Thus, our modeling analyses also under-estimate (to a lesser degree) the true offsite air impacts from Nucor's PM₁₀ and PM_{2.5} emissions.

Nucor performed further PM₁₀ and PM_{2.5} modeling in November, 2010. The results from these modeling analyses are not reflected in the draft permit distributed by LDEQ for public review and comment. In these November, 2010 modeling runs, Nucor analyzed the effects of modeled PM₁₀ and PM_{2.5} impacts from emission changes to sources COK103 and COK203 (coke battery quench-towers), and from splitting the iron ore and flux storage pile emissions between ground-level vehicle and pile-top wind erosion sources. Nucor's November, 2010 PM₁₀ and PM_{2.5} modeling analyses are better representations of actual quench tower and storage pile conditions at the pig iron/DRI facility than what they modeled in their permit application. Accordingly, we incorporated these revisions into our PM₁₀ and PM_{2.5} modeling analyses. The PM₁₀ and PM_{2.5} emissions and source parameters we modeled -- and that Nucor should have used -- are shown in the following tables:

See Tables Pages 88-92 of Zen-Noh Comments

LDEQ Response to Comment No. VII. 47

The Dock 1 Loading/Unloading Gantry Crane (DOC-101) (EQT 0017) and Dock 2 Loading/Unloading Gantry Crane (DOC-102) (EQT 0018) will work the receiving dock, unloading materials by clamshell bucket. Particulate emissions are controlled by water sprays. LDEQ has determined direct measurement of emissions is not technically feasible and prescribed work practice standards. The Title V permit also requires Nucor to analyze the moisture content of each product loaded or unloaded at the dock annually and to compare the sample moisture content values to those used in the most current application emission calculations, except that shipping records with documented moisture content can be substituted for the annual samples and analysis.

The applicant submitted a Dust Management Plan for the facility, which addresses fugitive dust controls for roadways. In the plan, the applicant indicates that permanent road sprinkler systems will be installed to water roadways and other unpaved areas on a routine and automatic basis. LDEQ believes this automatic delivery approach is a significant enhancement to typical truck-borne road watering plans and assigning a higher control efficiency factor is appropriate.

Regarding the need to monitor silt loading, moisture content, wind velocity, and the quantity of material handled and to conduct periodic inspections and daily visual observations, see the aforementioned Dust Management Plan, which requires actual monitoring of dust during both the construction and operation of the facility with deposition gauges, portable monitors, and visual inspections. This plan also includes quantifiable action levels and prescribes corrective actions. LDEQ has determined these work practice standards meet BACT for fugitive particulate emissions.

The applicant submitted the Dust Management Plan as evidence that high control efficiencies would be achievable. Figure 13.2.2-2 (Watering control effectiveness for unpaved travel surfaces) of AP-42 Section 13.2.2 – Unpaved Roads clearly shows that with sufficient watering and chemical suppressants, a control level of 90% is achievable. Spillage control measures are addressed by the plan. Similarly, trackouts can be controlled through the implementation of frequent sweeping or installation of wheel washing stations at paving transition points, or both. As stated in the BACT determination, paved roads must be maintained free of mud, dirt, and other materials in order to remain an effective option for controlling fugitive dusts. The commenter's reference to a specific, low control efficiency assigned to sweeping paved roads in AP-42 could not be found. Instead the document states that control efficiencies are variable and depend upon local silt loading conditions.

Moreover, the permit is not reliant on published control efficiencies. Nucor's Dust Management Plan requires actual monitoring of dust during both the construction and operation of the facility with deposition gauges, portable monitors, and visual inspections. This plan also includes quantifiable action levels and prescribes corrective actions. LDEQ has determined these work practice standards meet BACT for fugitive particulate emissions.

Sources COK102 and COK202 were modeled as point sources. Stack parameters for these sources are included on the EIQ sheets and in the permit. Due to the nature of these sources (notably extremely high temperature which will also lead to significant velocity), stack parameters most closely mimic the actual dispersion characteristics of the sources. COK101 and COK201 are also believed to be better characterized by point sources. Although these sources are not at the extremely elevated temperatures of COK102 and COK202, the temperatures are above ambient, and therefore, some velocity is expected. The permit includes stack testing conditions for all of these sources. Stack testing will verify whether these stack parameters are reasonable. If the stack parameters are found to be unreasonable, the facility may be required to modify the permit.

The applicant's roads were modeled as eighteen volume sources in order to avoid prohibitively long model run times necessitated by a large number of volume sources. By dividing emissions equally among eighteen volume sources and concentrating emissions in these areas, instead of spreading the emissions more equally throughout Nucor's property, the modeled results are conservative.

Calculations to determine emissions from roads involve a number of parameters, most of which cannot be accurately estimated unless they are measured at a specific site. This is impossible to do for Nucor since the facility has not yet been constructed. The values for these parameters can vary over a wide range and in many cases depend upon recent meteorological events, such as rainfall. The compilation of Air Pollutant Emission Factors indicates that unless site-specific periods of less than one year. However, even with higher confidence levels, unrepresentative modeling process is based on the assumption that emissions are continuous. The amount of road emissions is directly related to the type and amount of road traffic, which is usually not continuous or uniform. Combined with worst-case operating scenarios, the modeling tool will over predict concentrations, particularly in the vicinity of the source, and may incorrectly identify road emissions as the major cause of air pollution at a site. Often the use of control measures and best management practices are the most effective means to address off-property impacts from road sources.

Based on AP-42 13.2.Introduction to Fugitive Dust Sources, "...all roads are subject to some natural mitigation because of rainfall and other precipitation. The Equation 1a and 1b emission factors can be extrapolated to annual average uncontrolled conditions (but including natural mitigation)..." Nucor based annual tons/yr calculations on this equation. The average lb/hr rate was then derived from this TPY figure. To be conservative, the average lb/hr was multiplied by 1.5 to get a maximum lb/hr. This maximum lb/hr is what was input to the model for road emissions.

40 CFR 51 Appendix W discusses fugitive dust in Section 5.2.2.2.e. Fugitive dust usually refers to dust put into the atmosphere by the wind blowing over plowed fields, dirt roads or desert or sandy areas with little or no vegetation. Reentrained dust is that which is put into the air by reason of vehicles driving over dirt roads and dusty areas. Such sources can be characterized as line, area, or volume sources. Nucor followed the approved guidelines and modeled the roads as volume sources. Nucor combined the paved vs. unpaved road emissions since it has not yet been decided which roads will be paved. However, all emissions for both paved and unpaved roads are included in the modeling. The facility was asked to spread the volume sources over what would likely be the most used roadways. By creating more volume sources and covering all roadways, the emissions would have been further spread out and the impact of the emissions could have been minimized. By spreading out the emissions, the road emission representation in the model could have been viewed as not being conservative enough. LDEQ feels that the roadway representation is as conservative as possible, considering that the site has not yet been constructed. The mentioned roadways by the Zen-Noh facility will be used mainly for pile maintenance, and road emissions for those sources are addressed separately in the calculations for pile emissions.

PM₁₀ and PM_{2.5} were remodeled to address concerns from LDEQ. This document is included on a CD in EDMS¹⁴¹ dated October 15, 2010. The modeling that is referenced by the commenter was a sensitivity run based upon an increase in emissions that is permitted. The sensitivity run concluded that the change in emissions is insignificant, and therefore, the full modeling analyses did not need to be rerun.

Modeling methods employed by the applicant were the subject of extensive review by LDEQ, with support and comment from EPA Region 6. LDEQ has determined that the modeling presented by the applicant adequately approximates emissions from the facility, and the off-site impacts of those emissions, and these predicted impacts have demonstrated that emissions would not cause or contribute to air pollution in violation of any national ambient air quality standard.

Comment No. VII.48

PM₁₀ emissions from the aggregate DRI-pig iron facility will cause 24-hour PM₁₀ PSD increment and NAAQS violations. We corrected a number of Nucor's calculated PM₁₀ emission rates, including paved road, unpaved road, cooling tower, the DRI barge loading dock, and the Dock 1 loading/unloading gantry crane sources. The corrected PM₁₀ emissions, including modeled stack and volume source parameters, are included in the tables at the end of this comment (one for point sources and one for volume sources). Other than the corrected emission rates described above, we used Nucor's PM₁₀ modeling inputs in our modeling analyses.

Nucor obtained and processed background PM10 data, as they discuss in their October 5, 2010 air dispersion modeling protocol. These background data are to be added to modeled concentrations for verifying compliance with the 24-hour PM10 NAAQS.

In developing the background 24-hour PM10 concentrations, Nucor used the fourth high 24-hour concentration for each year at the Highway 1 Port Allen monitoring site. This is not an appropriate method for verifying compliance with the 24-hour PM10 NAAQS. The 24-hour PM10 NAAQS is "not to be exceeded more than once per year on average over 3 years." See <http://www.epa.gov/air/criteria.html>. Furthermore, in their 24-hour PM10 NAAQS compliance analysis, Nucor used the highest second high modeled impact for each year, which was then added to the fourth high 24-hour concentration for each year. Thus, Nucor's method of calculating total 24-hour PM₁₀ impacts (project plus

¹⁴¹ EDMS Document ID 7698085

background), will not verify compliance with the 24-hour PM₁₀ NAAQS.

Given our time constraints in reviewing Nucor's permit modeling analyses, we have not been able to obtain and process the correct background PM₁₀ data. For our analysis of Nucor's 24-hour PM₁₀ NAAQS, we used Nucor's background values for modeling years 2001 through 2005. For years 2006 through 2008, we used the fourth high 24-hour concentration averaged over years 2001 through 2005 (55 µg/m³). We recognize that this method will under-state total 24-hour PM₁₀ impacts from the project combined with background concentrations.

Scenario 1:

- Aggregate pig iron/DRIPM10 emissions;
- Baton Rouge Capitol Airport meteorological data, 2001 - 2005;
- Normal operating emissions;
- COK102 and COK202 modeled with 1.0 meter/second exit velocity (Nucor's modeled value).

This scenario uses the meteorological data Nucor prepared for their permit application modeling, as well as their unrealistic coke pushing "stack" exit velocities of 1.0 meter/second. These inputs will lead to an under-prediction bias in modeled impacts, since the meteorological data lacks all wind speeds less than 1.5 meters/second and the exit velocities will artificially over-state momentum plume rise.

For this scenario, Nucor's emissions result in a 158.6 µg/m³ highest second-high 24-hour PM₁₀ concentration. When added to the same-year background concentration (50 µg/m³), the total one-hour PM₁₀ concentration is 208.6 µg/m³. This is a violation of the 24-hour PM₁₀ NAAQS, with or without adding the background concentration. Other modeled years show similar results. These results are summarized in the following table.

Year of Meteorological Data	Highest 2 nd High 24-hr PM10 Concentration (µg/m ³)	Background 24-Hr PM10 Concentration (µg/m ³)	Total 24-Hr PM10 Concentration (µg/m ³)	24-Hr PM10 NAAQS (µg/m ³)	Easting Coordinate (meters)	Northing Coordinate (meters)
2001	155.15	58	213.15	150	705488.9	3327626.2
2002	148.45	52	200.45	150	705388.9	3327926.2
2003	158.60	50	208.60	150	705488.9	3327626.2
2004	155.05	60	215.05	150	705488.9	3327626.2
2005	148.01	56	204.01	150	705888.9	3327826.2

Nucor's highest second-high 24-hour PM₁₀ concentration (158.6 µg/m³) also violates the, 24-hour PM₁₀ PSD increment (30 µg/m³). This impact is solely due to PM₁₀ emissions from Nucor's aggregate pig iron/DRI facility. Other modeled years show similar results, and are summarized in the following table.

Year of Meteorological Data	Highest 2 nd High 24-hr PM10 Concentration (µg/m ³)	24-Hr PM10 PSD Increment (µg/m ³)	Easting Coordinate (meters)	Northing Coordinate (meters)
2001	155.15	30	705488.9	3327626.2
2002	148.45	30	705388.9	3327926.2
2003	158.60	30	705488.9	3327626.2

2004	155.05	30	705488.9	3327626.2
2005	148.01	30	705888.9	3327826.2

Scenario 2:

- Aggregate pig iron/DR! PM10 emissions;
- LDEQ's Baker wind speed and temperature data, 2005 - 2008;
- Normal operating emissions;
- COK102 and COK202 modeled with 1.0 meter/second exit velocity (Nucor's modeled value).

This scenario uses four years of AERMOD-ready meteorological data we prepared for our review of Nucor's permit application modeling. It also uses Nucor's unrealistic coke pushing "stack" exit velocities of 1.0 meter/second. These exit velocity inputs will lead to an under-prediction bias in modeled impacts, due to artificially over-stated momentum plume rise.

For this scenario, Nucor's emissions result in a 458.62 $\mu\text{g}/\text{m}^3$ highest second-high 24-hour PM_{10} concentration. When added to the background concentration (55 $\mu\text{g}/\text{m}^3$), the total one-hour PM_{10} concentration is 513.62 $\mu\text{g}/\text{m}^3$. This is a violation of the 24-hour PM_{10} NAAQS, with or without adding the background concentration. Other modeled years show similar conclusions. These results are summarized in the following table.

Year of Meteorological Data	Highest 2 nd High 24-hr PM_{10} Concentration ($\mu\text{g}/\text{m}^3$)	Background 24-Hr PM_{10} Concentration ($\mu\text{g}/\text{m}^3$)	Total 24-Hr PM_{10} Concentration ($\mu\text{g}/\text{m}^3$)	24-Hr PM_{10} NAAQS ($\mu\text{g}/\text{m}^3$)	Easting Coordinate (meters)	Northing Coordinate (meters)
2005	394.21	56	450.21	150	705788.9	3327726.2
2006	324.99	55	379.99	150	705788.9	3327626.2
2007	373.56	55	428.56	150	705688.9	3327626.2
2008	458.62	55	513.62	150	705588.9	3327726.2

Nucor's highest second-high 24-hour PM_{10} concentration (458.62 $\mu\text{g}/\text{m}^3$) also violates the 24-hour PM_{10} PSD increment (30 $\mu\text{g}/\text{m}^3$). This impact is solely due to PM_{10} emissions from Nucor's aggregate pig iron/DRI facility. Other modeled years show similar results, and are summarized in the following table.

Year of Meteorology	Highest 2 nd High 24-hr PM_{10} Concentration	24-Hr PM_{10} PSD Increment	Easting Coordinate	Northing Coordinate
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Data	($\mu\text{g}/\text{m}^3$)	($\mu\text{g}/\text{m}^3$)	(meters)	(meters)
2005	394.21	30	705788.9	3327726.2
2006	324.99	30	705788.9	3327626.2
2007	373.56	30	705688.9	3327626.2
2008	458.62	30	705588.9	3327726.2

LDEQ Response to Comment No. VII.48

The commenter states that he “corrected a number of Nucor’s calculated PM₁₀ emission rates, including paved road, unpaved road, cooling tower, the DRI barge loading dock, and the Dock 1 loading/unloading gantry crane sources.” However, the comment does not present what calculations the commenter believes were in error, and proceeds to conduct an air quality analysis on the basis of undisclosed emission rates. Presumably, the commenter is inferring and continuing Comments 45, 46, 47, 75, 97 and 98, although no direct connection to these comments are made. Please see LDEQ Response to Comment Nos. 45, 46, 47, 75, 97 and 98, and LDEQ Response to Comment No. VII. 117 in the Public Comments Response Summary for permits 2560-00281-V0 and PSD-LA-740, for specific responses to the implied emission rate concerns raised by this comment. LDEQ considers the modeling results presented by the commenter to be based on flawed emission calculations, and therefore inappropriate for the sources in question.

Modeling methods employed by the applicant were the subject of extensive review by LDEQ, with support and comment from EPA Region 6. LDEQ has determined that the modeling presented by the applicant adequately approximates emissions from the facility, and the off-site impacts of those emissions, and these predicted impacts have demonstrated that emissions would not cause or contribute to air pollution in violation of any national ambient air quality standard.

See LDEQ Response to Comment VII.47.

40 CFR 51 Appendix W states the following in section 7.2.1.1.b:

If the air quality analyses are conducted using the period of meteorological input data recommended in subsection 8.3.1.2 (e.g., 5 years of National Weather Service (NWS) data or at least 1 year site specific data; subsection 8.3.3), then the design concentration based on the highest, second-highest short term concentration over the entire receptor network for each year modeled or the highest long term average (whichever is controlling) should be used to determine emission limitations to assess compliance with the NAAQS and PSD increments. For the 24-hour PM-10 NAAQS (which is a probabilistic standard)—when multiple years are modeled, they collectively represent a single period. Thus, if 5 years of NWS data are modeled, then the highest 6th highest concentration for the whole period becomes the design value. And in general, when n years are modeled, the (n+1)th highest concentration over the n-year period is the design value, since this represents an average or expected exceedance rate of one per year.

Nucor used the high second high value from the modeling results and paired it with the previously approved background data from the original Pig Iron Facility permit. LDEQ believes that Nucor’s method of calculating total 24-hour PM₁₀ impacts complies with 40 CFR 51 Appendix W and will verify compliance with the 24-hour PM₁₀ NAAQS.

LDEQ also notes that the background data for PM₁₀ used in this project is the same as the background data used in the original Pig Iron Facility permit. The background data has been available in the record since that time and no objection was received on the use of this data.

Comment No. VII.49

PM_{2.5} emissions from the aggregate DRI-pig iron facility will cause 24-hour and annual PM_{2.5} NAAQS violations. We corrected a number of Nucor's calculated PM_{2.5} emission rates, including paved road, unpaved road, cooling tower, the DRI barge loading dock, and the Dock 1 loading/unloading gantry crane sources. The corrected PM_{2.5} emissions, including modeled stack and volume source parameters, are included in the tables at the end of this comment (one for point sources and one for volume sources). Other than the corrected emission rates described above, we used Nucor's PM_{2.5} modeling inputs in our modeling analyses.

Nucor obtained and processed background PM_{2.5} data, as they discuss in their October 5, 2010 air dispersion modeling protocol. These background data are to be added to modeled concentrations for verifying compliance with the 24-hour and annual PM_{2.5} NAAQS. USEPA guidance on verifying the annual PM_{2.5} NAAQS is as follows:

The modeled annual concentrations of (primary) PM_{2.5} to be added to the monitored annual design value should be computed using the same procedure used for the initial significant impact analysis based on the highest average of the modeled annual averages across 5 years for NWS meteorological data or the highest modeled annual average for one year of site-specific meteorological data. The resulting cumulative annual concentration would then be compared to the annual PM_{2.5} NAAQS of 15 µg/m³. See USEPA, Modeling Procedures for Demonstrating Compliance with the PM_{2.5} NAAQS, March 23, 2010, p. 8.

Nucor analyzed 2007 through 2009 PM_{2.5} data from the Bayou Plaquemine monitor. Using these data, Nucor calculated a three-year average PM_{2.5} concentration of 9.6 µg/m³. This value is to be added to the multi-year modeled average of the PM_{2.5} concentration at each receptor.

USEPA guidance on verifying the 24-hour PM_{2.5} NAAQS is as follows:

For the 24-hour NAAQS analysis, the modeled concentrations to be added to the monitored 24-hour design value should be computed using the same procedure used for the preliminary analysis based on the highest average of the maximum modeled 24-hour averages across 5 years for NWS meteorological data or the maximum modeled 24-hour average for one year of site-specific meteorological data. As noted above, use of the average modeled concentration across the appropriate time period more accurately characterizes the modeled contribution from the facility in relation to the NAAQS than use of the highest modeled impact from individual years, while using the average of the first highest 24-hour averages rather than the 98th percentile (8th highest) values is consistent with the screening nature of PM_{2.5} dispersion modeling. Furthermore, combining the 98th percentile monitored with the 98th percentile modeled concentrations for a cumulative impact assessment could result in a value that is below the 98th percentile of the combined cumulative distribution and would, therefore, not be protective of the NAAQS.

See USEP A, Modeling Procedures for Demonstrating Compliance with the PM_{2.5} NAAQS, March 23, 2010, p. 8.

Nucor's analysis of 2007 through 2009 PM_{2.5} data from the Bayou Plaquemine monitor identified a three-year average 98th percentile 24-hour PM_{2.5} concentration of 19.3 µg/m³. This value is to be added to the multi-year modeled average of the highest 24-hour PM_{2.5} concentration at each receptor. Our analysis of Nucor's 24-hour and annual PM_{2.5} NAAQS used Nucor's background data calculations.

Scenario 1:

- Aggregate pig iron/DRIPM_{2.5} emissions;
- Baton Rouge Capitol Airport meteorological data, 2001 - 2005;
- Normal operating emissions;
- COK102 and COK202 modeled with 1.0 meter/second exit velocity (Nucor's modeled value).

This scenario uses the meteorological data Nucor prepared for their permit application modeling, as well as their unrealistic coke pushing "stack" exit velocities of 1.0 meter/second. These inputs will lead to an under-prediction bias in modeled impacts, since the meteorological data lacks all wind speeds less than 1.5 meters/second and the exit velocities will artificially over-state momentum plume rise.

For this scenario, Nucor's emissions result in a 5.68 µg/m³ highest five-year average PM_{2.5} concentration. When added to the three-year average background concentration (9.6 µg/m³), the total annual PM_{2.5} concentration is 15.28 µg/m³. This is a violation of the annual PM_{2.5} NAAQS, as shown below.

2001-- Average Annual Concentration (µg/m ³)	Background Concentration (µg/m ³)	Total Concentration (µg/m ³)	Average Annual NAAQS (µg/m ³)	Easting Coordinate (meters)	Northin Coordi (meters)
5.68	9.6	15.28	15	705488.9	332762

Nucor's emissions also result in a 25.12 µg/m³ five-year average highest 24-hour PM_{2.5} concentration. When added to the three-year average background concentration (19.3 µg/m³), the total 24-hour PM_{2.5} concentration is 44.42 µg/m³. This is a violation of the 24-hour PM_{2.5} NAAQS, as shown in the following table.

2001-- 2005 Average Hr PM _{2.5} Concentration (µg/m ³)	Background Concentration (µg/m ³)	Total Concentration (µg/m ³)	24-Hr NAAQS (µg/m ³)	Easting Coordinate (meters)	Northin Coordi (meters)
25.12	19.3	44.42	35	705488.9	332762

Scenario 2:

- Aggregate pig iron/DRI PM_{2.5} emissions;
- LDEQ's Baker wind speed and temperature data, 2005 - 2008;
- Normal operating emissions;
- COK102 and COK202 modeled with 1.0 meter/second exit velocity (Nucor's modeled value).

This scenario uses four years of AERMOD-ready meteorological data we prepared for

our review of Nucor's permit application modeling. It also uses Nucor's unrealistic coke pushing "stack" exit velocities of 1.0 meter/second. These exit velocity inputs will lead to an under-prediction bias in modeled impacts, due to artificially over-stated momentum plume rise.

For this scenario, Nucor's emissions result in a 10.25 $\mu\text{g}/\text{m}^3$ highest four-year average $\text{PM}_{2.5}$ concentration. When added to the three-year average background concentration (9.6 $\mu\text{g}/\text{m}^3$), the total annual $\text{PM}_{2.5}$ concentration is 19.85 $\mu\text{g}/\text{m}^3$. This is a violation of the annual $\text{PM}_{2.5}$ NAAQS, as shown below.

2005-2008 Average Annual $\text{PM}_{2.5}$ Concentration ($\mu\text{g}/\text{m}^3$)	Background Concentration ($\mu\text{g}/\text{m}^3$)	Total Concentration ($\mu\text{g}/\text{m}^3$)	Average Annual NAAQS ($\mu\text{g}/\text{m}^3$)	Easting Coordinate (meters)	North Coordinate (meters)
10.25	9.6	19.85	15	705588.9	332762

Nucor's emissions also result in a 58.19 $\mu\text{g}/\text{m}^3$ five-year average highest 24-hour $\text{PM}_{2.5}$ concentration. When added to the three-year average background concentration (19.3 $\mu\text{g}/\text{m}^3$), the total 24-hour $\text{PM}_{2.5}$ concentration is 77.49 $\mu\text{g}/\text{m}^3$. This is a violation of the 24-hour $\text{PM}_{2.5}$ NAAQS, with or without added background, as shown in the following table.

2005-2008 Average Hr $\text{PM}_{2.5}$ Concentration ($\mu\text{g}/\text{m}^3$)	Background Concentration ($\mu\text{g}/\text{m}^3$)	Total Concentration ($\mu\text{g}/\text{m}^3$)	24-Hr NAAQS ($\mu\text{g}/\text{m}^3$)	Easting Coordinate (meters)	North Coordinate (meters)
58.19	19.3	77.49	35	705588.9	332772

In sum, we corrected a number of Nucor's calculated PM_{10} and $\text{PM}_{2.5}$ emission rates, including paved road, unpaved road, cooling tower, the DRI barge loading dock, and the Dock 1 loading/unloading gantry crane sources. We then remodeled these corrected emissions using the same model, source release parameters, and meteorological data as used in Nucor's permit application. As discussed above, using Nucor's Baton Rouge Capitol Airport meteorological data will significantly under-predict modeled impacts. Nucor's incorrect road configuration modeling and exaggerated exit velocities for coke oven pushing activities will further under-estimate modeled impacts.

It is clear that correcting Nucor's PM_{10} emission calculations will result in 24-hour PM_{10} PSD increment violations and 24-hour PM_{10} NAAQS violations. Correcting Nucor's $\text{PM}_{2.5}$ emission calculations will also result in 24-hour and annual $\text{PM}_{2.5}$ NAAQS violations. The DRI PSD permit and modified pig iron Part 70 permit must be denied because of these modeled PM_{10} and $\text{PM}_{2.5}$ violations.

LDEQ Response to Comment No. VII.49

Comment No. VII. 49 is substantially the same as Comment No. VII.48, but specific to emissions of $\text{PM}_{2.5}$ rather than PM_{10} . See LDEQ's Response to Comment No. VII.48 for our response to this comment.

See LDEQ Response to Comment VII.47.

Comment No. VII.50

Nucor used flawed methods for modeling road emissions. Nucor modeled the road emissions as 18 separate volume sources, which they placed in discrete locations throughout their proposed plant road system. The modeled source locations purport to represent the road dust emissions, but in fact they do not.

First, the 18 volume sources only cover part of the proposed road system. For example, the road to the west of the storage piles is completely excluded from the modeling analyses. This road, which borders the Zen-Noh property, could be causing even higher offsite PM₁₀ and PM_{2.5} impacts than has been modeled. Excluding emissions from that road segment results in an incomplete modeling analysis.

Second, the placement of the 18 volume sources, even if they were placed on all the roads (which they were not), is inadequate for modeling road emissions. Road emissions must be modeled as a series of volume sources, such that they represent a line source covering the roads. Alternatively, the roads can be modeled as AERMOD area sources, such as AREAPOL Y sources that cover the exact locations of the plant roadways. *See USEPA, Example Application of Modeling Toxic Air Pollutants in Urban Areas, EPA-4541R-02-003, June 2002, pp. 14-15.* Nucor's modeling approach only covers a small percentage of the identified roads, and thus incorrectly assesses air impacts from the associated fugitive dust emissions.

Third, Nucor combined the emissions from paved and unpaved roads and assigned them equally to the 18 volume sources they modeled. Paved and unpaved roads should always be modeled separately, as it is impossible for a road to both paved and unpaved at the same time. Nucor must identify which of their roads will be paved and which will be unpaved, and remodel the emissions accordingly. Presumably, Nucor knows which roads will be paved and unpaved, as they calculated emissions for these activities using vehicle miles traveled for each road type. To perform these emission calculations, Nucor had to have some idea of the length of the unpaved and paved roads, but they failed to disclose this information to both LDEQ and the reviewing public. LDEQ cannot issue Nucor's PSD permit without a complete remodeling of the fugitive dust from paved and unpaved roads. The revised modeling must also use AERMOD input meteorological data with LDEQ-measured wind data, and not the faulty Baton Rouge Airport data used in the permit application modeling.

Nucor should be required to resubmit ambient air quality modeling using appropriate methods for road emissions.

LDEQ Response to Comment No. VII.50

See LDEQ Response to Comment VII.47.

Modeling methods employed by the applicant were the subject of extensive review by LDEQ, with support and comment from EPA Region 6. Fugitive emissions from roads are necessarily dispersed in nature, and a series of volume sources approximating this dispersal was deemed appropriate by the reviewing agencies. LDEQ has determined that the modeling presented by the applicant adequately approximates fugitive emissions from roads, and the off-site impacts of those emissions, and these predicted impacts have demonstrated that the emissions would not cause or contribute to air pollution in violation of any national ambient air quality standard.

Comment No. VII. 51

Nucor's air modeling uses Baton Rouge Airport wind data, which excludes low wind speeds necessary for verifying compliance with the NAAQS and Class II PSD increments. Nucor's modeling analysis used five years of surface meteorological data collected at the Baton Rouge Airport. These five years of data (2001 through 2005) were processed so as to be usable in the recently-approved USEPA AERMOD air dispersion model.

For air dispersion modeling purposes, airport wind data are among the least desirable. The USEP A, in their Meteorological Monitoring Guidance for Regulatory Modeling Applications, summarizes these concerns about using airport data:

For practical purposes, because airport data were readily available, most regulatory modeling was initially performed using these data; however, one should be aware that airport data, in general, do not meet this guidance. See USEP A, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-4541R-99-05, February 2000, p. 1-1.

Airport data were initially used for simpler Gaussian dispersion models such as ISCST, ISCST2, and even ISCST3. It was also used for older, less-refined models such as MPTER, CRSTER, and COMPLEX-III. The key word is *initially*. The primary reason for using airport data was that they were "readily available."

The main problem with airport data, even recent data collected using Automated Surface Observing Systems (ASOS) instruments, is that all wind speeds less than three knots (about 1.5 meters/second) are automatically regarded as calm, even if the wind is not entirely still. Calm hours are reported as 0.0 meter/second, and are then excluded from the modeling analysis. This is true even with the latest USEPA model, AERMOD.

The purpose of the airport calm reporting procedure is simple: *winds less than three knots do not pose a concern for pilots, so airports identify all low wind speed conditions as calm.* The problem with using these data for air permitting is that the best wind conditions for landing and take offs (low wind speeds) are typically the worst-case conditions for air pollution impacts.

Low wind speeds (less than or equal to 1.0 meter/second) are usually associated with peak air quality impacts because modeled impacts are *inversely* proportional to wind speed. This is particularly true for low-level emission sources, such as fugitive dust from roads and material storage and handling at iron and steel facilities. Using airport data, with no winds less than 1.5 meters/second, gives an under-prediction bias by eliminating most of the worst-case modeling conditions. In other words, what's good for pilots is bad for air quality.

Following USEPA guidance, wind speed measuring devices (anemometers) should have a starting threshold of 0.5 meter per second (about one knot) or less. *Id.*, p. 5-2. In effect, airport wind speed data have a starting threshold *over three times* that level.

Nucor's pig iron and DRI permit application modeling both used five years of meteorological data collected at the Baton Rouge Airport. Using airport data, which are always sanitized of any wind speeds less than 1.5 meters/second, results in severely underestimated modeled impacts. This concern is particularly true in this matter, as Nucor's 24-hr PM₁₀ air modeling results are over 82% of the available PSD increment. The wind data collected at the Baton Rouge Airport are simply inadequate to provide AERMOD with the required parameters needed for verifying compliance with the

NAAQS and PSD increments. Just because one can run AERMOD with airport data does not imply that one should do so.

The meteorological data files from the Baton Rouge Airport include an extremely large percentage of calm hours. Out of a possible 43,824 hours in the Baton Rouge five-year modeling data set (2001 through 2005), there are 10,082 calm hours. This represents over 23% of the total data set. Typically, when properly measured with modern anemometers, there are only a few percent calm hours in a meteorological data base per year. (For example, the LDEQ wind data for Baton Rouge Capitol include only 88 calm hours for year 2008. Other LDEQ wind data sets have a few percent calms per year). In addition, the five years of Baton Rouge Airport data modeled by Nucor have 3,555 missing hours. Since neither calm nor missing hours can be used by AERMOD, over 31.1 % of the meteorological data are discarded. In total, less than 69% of the total data are actually used in Nucor's modeling analysis. As discussed above, these missing hours contain the worst -case dispersion conditions and excluding them from the modeling will underestimate project impacts.

Without a doubt, the conditions most crucial for verifying compliance with the NAAQS and PSD increments (low wind speeds) are excluded from the Nucor modeling analysis because they are using 2001-2005 Baton Rouge Airport wind data. This is particularly disconcerting given that AERMOD is designed to handle wind speeds down to 0.28 meter/second, while older, less-refined models cannot do so.

Sensitive and accurate measurements of wind speeds are necessary for measuring winds down to 0.5 meter per second or less, which can then be used as valid hours in the air dispersion modeling analyses. There would be no need to label such low wind speed hours as calm, which will greatly increase the number of hours included in the modeling analyses. It is these low wind speed hours that must be included in the modeling data set for realistically verifying Nucor's compliance with the NAAQS and PSD increments.

A. Replacing standard ASOS data with true hourly-average winds will increase modeled impacts.

The AERMOD Implementation Workgroup, a group of Federal and State air dispersion modeling staff, have documented that using AERMOD with airport meteorological data will likely underestimate modeled impacts. This is because of the high number of calm and missing hours in standard ASOS data, such as that used by Nucor in their permit application modeling. *See* AERMOD Implementation Workgroup, ASOS and Met Data Processing Subgroup, EPA R/S/L Modelers Workshop, May 12-14, 2009, pp. 3-4.

The AERMOD Implementation Workgroup have been developing a method to use one-minute average ASOS data collected at airports to calculate hourly-averaged winds that can then be used by AERMOD. These data can be used to replace standard ASOS data, such as were used in the Nucor permit application modeling. Standard ASOS data from airports are based on two-minute winds measured 10 minutes before the hour, and wind speeds less than three knots are reported as calm.

The hourly values calculated using one-minute average ASOS data would not be biased by the high number of missing low wind speed hours seen in Standard ASOS data.. Furthermore, including low wind speed hours would be consistent with the data sets that were used to evaluate AERMOD in the first place. In other words, airport meteorological data that exclude low wind speeds are inconsistent with the data used to develop and evaluate AERMOD. From the AERMOD Implementation Workgroup:

- AERMOD was validated with low wind speeds similar to 1-min ASOS, lack of low wind speeds in std. ASOS may (will) result in under-prediction of impacts. *Id.*, p. 4.
- In a presentation to the Workgroup, Mr. Joe Sims, of the Alabama Department of Environmental Management, commented:
- In almost all cases, the predicted concentrations using lighter winds were higher than when using standard ASOS - as expected.
- I was especially interested in point sources in a rural environment. This combination constitutes the vast majority of PSD applications we see in Alabama. The ratios in this category are pretty much in the 1 to 2 range. Applicants won't like this but it could be a lot worse. *Id.*, p. 19.
- Mr. Sims concluded his presentation as follows:
- Using the hourly averaged 1-minute ASOS data to better represent dispersion potential from a source makes a lot of sense.
- Including observed light winds and significantly reducing the number of hours with no usable winds logically produces more accurate results.
- The generally higher predicted concentrations would be more protective of human health.
- We as regulators must be prepared for challenges (and complaints) from the regulated community. *Id.*, p. 20.

In essence, the AERMOD Implementation Workgroup calculated hourly averaged wind data using one-minute average ASOS data, and then processed these data in the AERMOD meteorological data pre-processor, AERMET. They treated these meteorological data with the on-site pathway in AERMET processing. *Id.*, p. 10. This is the method used to develop AERMOD-ready input data using both on-site and site-specific data. These data invariably result in higher modeled concentrations than standard ASOS data, simply because they contain the low wind speeds that are most culpable for peak impacts. In other words, the Workgroup did not arbitrarily redefine all winds less than three knots as calm, as is done with standard ASOS data.

The AERMOD Implementation Workgroup's method to develop hourly wind values calculated using one-minute average ASOS data is not currently available to the public. Their concern that AERMOD under estimates modeled impacts when run with standard ASOS is very important, however, and must be addressed in the Nucor permit application process. For example, this concern is heightened in the Nucor permit application, since the 24-hour PM₁₀ modeled impacts using standard ASOS data are already close to the allowable PSD increment.

B. Replacing standard ASOS data with LDEQ's measured hourly-average winds will increase modeled impacts.

USEPA's AERMET program handles three types of meteorological data: Surface data from airports, upper air data from twice-daily radiosonde measurements, and site-specific meteorological parameters collected at the surface and at profiles above the surface. *See* USEPA, User's Guide for the AERMOD Meteorological Preprocessor (AERMET), EPA-454/B-03-002, November 2004, p. 1-1. Site-specific data are the preferred meteorological parameters for air dispersion model inputs. *See* USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005, Section 8.3.3.

LDEQ measures wind speed, wind direction, and ambient air temperature at a number of

their air monitoring sites. *See* <http://www.deq.louisiana.gov/portal/tabid/112/Default.aspx>. LDEQ's wind speed data reports values starting at one mile per hour; lower wind speed values are reported as calm. These data can be used in AERMOD, and have the advantage of including the low wind speed hours missing in the standard ASOS data used by Nucor in their permit application modeling.

LDEQ acknowledges that their monitoring data can be used in AERMOD, and specifies Baker as a surrogate surface station for modeling impacts in the Capitol region of their jurisdiction (the region where the proposed Nucor project is located). LDEQ specifies the Baton Rouge Airport as the primary surface station for this region, and Lake Charles is listed as the primary upper air station. Nucor, however, did not use any surface data from Baker or other LDEQ sites, instead relying solely on faulty standard ASOS data from the Baton Rouge Airport.

We analyzed the effects on modeled concentrations of using LDEQ surface meteorological data as the primary input to AERMOD, rather than the standard ASOS Baton Rouge Airport data. From LDEQ, we obtained wind speed, wind direction, and ambient temperature data for the following sites and years:

Baker: 2005 through 2008
Baton Rouge Capitol: 2005 and 2008
Bayou Plaquemine: 2005
Dutchtown: 2005 through 2008
French Settlement: 2005 through 2008

We also obtained 2004 data for these sites; however, there were problems with reported wind speed values that make the data currently unusable for modeling. Our analysis of these data focus on Baker as the primary data source, as it is closest to the Baton Rouge Airport. The other sites are closer to the proposed Nucor site than the Baton Rouge Airport, and thus also qualify as being more site-specific than the Baton Rouge Airport data.

For calculating stability parameters, cloud cover and ceiling height from the airport data are still required, as are upper air data from twice-daily radiosonde launches. For these purposes, we used the Baton Rouge Airport and Lake Charles FSL upper air data, respectively. In essence, we used the same airport and upper air data as did Nucor, but substituted 10-meter wind speed, wind direction, and ambient air temperature data from nearby LDEQ monitoring sites.

We processed the Baton Rouge surface meteorological data and Lake Charles upper air data with USEPA's AERMET program (v. 06341). The data processing can be summarized as follows:

- We obtained 2004 through 2008 Baton Rouge Airport Integrated Surface Hourly Data (ISHD) files from the National Climatic Data Center (NCDC). These data are readily available on yearly ISHD DVDs or by downloading from NCDC's website. These surface data were processed through AERMET Stage 1, which performs data extraction and quality control checks.
- We obtained twice-daily upper air soundings from the Lake Charles Airport for January 1, 2004 through January 1, 2009. These soundings are in FSL format and data are readily available by downloading from the National Oceanic and Atmospheric Administration's FSL website. These upper air data were processed

through AERMET Stage 1, which performs data extraction and quality control checks.

- We obtained hourly wind speed, wind direction, and ambient air temperature data from LDEQ. These data were converted to the required AERMET units, and processed through AERMET Stage 1, which performs data extraction and quality control checks. The data were processed in the "onsite" pathway, which is the same method used by the AERMOD Implementation Workgroup in their analysis of hourly ASOS versus standard ASOS meteorological data.
- We merged the surface, LDEQ, and upper air data using AERMET stage two. Missing data were not filled.
- We processed the merged files in AERMET stage three. We used the LDEQ-recommended surface roughness, albedo, and Bowen ratio inputs as listed in their modeling procedures. These are the same surface roughness, albedo, and Bowen ratio inputs used in the Nucor modeling analysis. Except for one exception, we did not substitute Baton Rouge Airport wind data for missing LDEQ data. AERMET Stage three creates the model-ready surface and profile data files required by AERMOD.

Our overall methodology appears to be the same approach for processing surface airport and upper air data as was used in developing the AERMOD input meteorology modeled in Nucor's permit application. We reach this conclusion by preparing a 2005 data set using only Baton Rouge Airport surface data and Lake Charles upper air data (no LDEQ wind data), and comparing the missing and calm hours with the 2005 data set used by Nucor. The results are equivalent.

LDEQ must not issue Nucor's PSD permit, which is based on faulty meteorological data. Nucor's analysis is unacceptable because it used meteorological data that are unsuitable for verifying compliance with the NAAQS and PSD increments.

LDEQ Response to Comment No. VII.51

Modeling for criteria pollutants was performed using the EPA approved AERMOD model to determine compliance with the NAAQS and PSD increments. According to 40 CFR 51 Appendix W Section 8.3.4.1.a, "Treatment of calm or light and variable wind poses a special problem in model applications since steady-state Gaussian plume models assume that concentration is inversely proportional to wind speed. Furthermore, concentrations may become unrealistically large when wind speeds less than 1m/s are input to the model. Procedures have been developed to prevent the occurrence of overly conservative concentration estimates during periods of calms. These procedures acknowledge that a steady-state Gaussian plume model does not apply during calm conditions, and that our knowledge of wind patterns and plume behavior during these conditions does not, at present, permit the development of a better technique. Therefore, the procedures disregard hours which are identified as calm. The hour is treated as missing and a convention for handling missing hours is recommended."

Also, according to 40 CFR 51 Appendix W Section 8.3.4.2.a, "Hourly concentrations calculated with steady-state Gaussian plume models using calms should not be considered valid; the wind and concentration estimates for these hours should be disregarded and considered to be missing. Critical concentrations for 3-, 8-, and 24-hour averages should be calculated by dividing the sum of the hourly concentrations for the period by the number of valid or non-missing hours. If the total number of valid hours is less than 18 for 24-hour averages, less than 6 for 8-hour averages or less than 3 for 3-hour averages, the total concentration should be divided by 18 for the 24-hour average, 6 for the 8-hour averages or less than 3 for the 3-hour average. For annual averages, the sum of all valid hourly concentrations is divided by the number of non-calm hours during the year. AERMOD has been coded to implement these instructions."

In addition to appropriately utilizing the EPA-preferred model for near-field applications, the modeling for Nucor's permit application followed approved LDEQ modeling guidelines. Nucor used the LDEQ recommended met stations for its modeling demonstration. LDEQ cannot allow other facilities to use this data without allowing Nucor to use it also. To do so could be seen as arbitrary and capricious by the public and regulated community.

Louisiana's continued use of airport meteorological data for modeling projects is based on the studies performed by the Modeling Workgroup used to evaluate AERMOD's behavior in comparison with ISC. The Modeling Workgroup consisted of members of both the regulatory and regulated communities. The case studies involved source/geography configurations typical to Louisiana industrial facilities. The results of these analyses along with case studies already put forth by EPA and other groups were used to develop updated modeling guidance for Louisiana, including the development of site-specific parameters required by AERMOD for the various geographic regions of the state. The default AERMOD meteorological variables were also studied. Case studies were performed to investigate sensitivity of the land-use parameters (i.e., surface roughness length, Bowen ratio, and albedo) and to determine the most conservative land use parameters to use as defaults in each region. These defaults are listed by regional office in the Louisiana Air Quality Modeling Procedures¹⁴² as a conservative option in lieu of more site-specific information. In this study, the use of appropriate meteorological data was also carefully reviewed, due to the potential burden to the regulated community in processing the meteorological data. Using the case studies and literature review findings, LDEQ decided to allow modeling analyses to continue to utilize one of the four primary surface meteorological stations in Louisiana. These methods have been the accepted practice in Louisiana since August of 2006 when the updated Air Quality Modeling Procedures were made public.

Comment No. VII.52

LDEQ should require Nucor to use flag-pole receptors to determine compliance with the NAAQS and PSD increments because there are elevated work platforms near the Nucor plant. Nucor performed all their AERMOD model runs using ground-level receptors. Nucor's modeled receptors were placed on the surface of the ground, even though AERMOD allows receptors to be placed at discrete heights above the ground surface. Elevated receptors are referred to as flagpole receptors in the AERMOD model.

Many of Nucor's emissions are released from tall stacks with significant plume rise characteristics. This results in elevated effective stack heights where the plume centerline remains well above the surface for extended distances from the source. For these emission releases, the air concentration increases with height above the ground, with a maximum at the plume centerline.

The proposed Nucor project is adjacent to the existing Zen-Noh grain facility. Zen-Noh has many tall structures, including elevators, conveyors, buildings, and catwalks where their employees have access and routinely work. The USEPA Model Clearinghouse has advised Regional Offices that the appropriate method to use when modeling receptors on tall structures is to treat these receptors as "flagpoles." See USEPA, Activities of the Modeling Clearinghouse, A Summary Report FY81- FY85, EPA-450/4-86-006, May 1986, p. 18. Nucor did not model flagpole receptor at the Zen-Noh facility despite EPA Region 5's request, in March 2009, that Nucor do so. As a result, Nucor's modeling does not adequately demonstrate that there will not be an exceedance of a NAAQS or PSD

¹⁴² Available at: <http://www.deq.louisiana.gov/portal/Portals/0/AirQualityAssessment/Engineering/Modeling/Modeling%20Procedures%200806.pdf>

increment. Nucor's NAAQS and PSD increment modeling is incomplete without the information that would be provided by modeling flagpole receptors, and LDEQ should require Nucor to provide that information. LDEQ should make the revised ambient air quality analysis available for public review and comment at a public hearing. *See* 42 U.S.C. § 7475(a)(2). LDEQ should also require Nucor to use flagpole receptors in its modeling of TAPs, to assure that there are no AAS violations. *See* LAC 33:III.5109 .B.

LDEQ Response to Comment No. VII.52

Requiring Nucor to model any type of elevated platform that is not for public use (i.e., a bridge) is unprecedented, and would require information from nearby facilities that is not readily available to LDEQ. Nucor is not required to demonstrate compliance with the PSD increment and NAAQS at flagpole receptors that do not represent public thoroughways.

The question of flagpole receptors for elevated sources was raised at a meeting with EPA Region 6 staff on March 3, 2009. EPA's position is that public access locations, such as bridges, should be modeled using flagpole receptors, but private industrial areas should not.

Within the dispersion model, receptors can be assumed to be at ground level or above the terrain as if set on a pole. These are known as flagpole receptors. EPA has indicated that flagpole receptors are not acceptable for use in regulatory (permit) applications. Instead, flagpole receptors should only be used on a case-by-case basis for model evaluation purposes. The reason for this is that full ground reflection is not represented in flagpole receptors.

It is both convention and the default mode to assume a height of zero meters above ground to represent ambient air. This convention should be followed for regulatory modeling purposes. On a case-by-case basis, EPA has allowed the use of flagpole receptors where there would be a significant amount of public access (i.e., elevated bridges). Nucor included flagpole receptors on elevated bridges, and the modeling demonstrated compliance with the NAAQS at these receptors.

Comment No. VII.53

The Alternate Operating Scenario does not comply with PSD or Title V. The DRI application includes a discussion of an alternate operating scenario that would allow elimination of the large reformer via substitution of a gas heater. According to Nucor, this process is experimental and has never been applied to a DRI facility the size of the Project. Nucor explains:

Fundamentally, the alternative reformer-less project (developed by HYL) replaces the reformer with a much smaller process heater and operating the shaft furnace under limited pressure, instead of atmospheric conditions. The smaller process heater and pressure operation allows reduction in the size of the process boiler otherwise required to support the DRI process.

The use of the experimental process, if selected, would replace the reformer with a process heater having a smaller heat input, and allow for reduction in the process boiler size. Other emission points are essentially unaffected by the change. Nucor would commit to meeting BACT limits established for the traditional process for all emission points and presents a separate BACT determination for the process heater.

The DRI PSD permit and Part 70 permit do not include the evaluation of an alternate operating scenario. Neither the DRI Application nor the proposed permits discuss or evaluate this alternative operating scenario. There is no application nor are there any

emission calculations for this option. However, it appears that Nucor and LDEQ have been discussing the potential effects of this alternate operating scenario. For example, the Worksheet for Technical Review of the Working Draft of the Proposed Permit discusses the DRI Part 70 permit Specific Requirement #316. Nucor states that "[t]here is no Alternate Operating for this requirement to affect." LDEQ's response stated that "additional language was added," which appears to refer to Section XI, Operational Flexibility, in the Part 70 permit Statement of Basis rather than a change in the Specific Requirement. In fact, the Specific Requirement with the highest running number is #313, indicating that Specific Requirements #314 through #316 have been eliminated. Nevertheless, the Part 70 permit states that "Nucor is investigating the potential of a DRI process that does not require a reformer as part of the design" in which reformer would be replaced by a process heater providing the energy input necessary to heat the furnace. This potential process change must be evaluated as part of the PSD and Title V permit processes.

LDEQ Response to Comment No. VII.53

The commenter is correct in the assertion that the DRI PSD and Part 70 permits do not include an evaluation of the alternate operating scenario presented on the basis of the HYL design. The applicant presented the possibility of an alternate design to the calculations and regulatory analysis presented in the application, in the spirit of full disclosure that design contracts had not been finalized. It was indicated that the calculations and regulatory analysis presented were considered to be the most conservative with respect to the two designs. The applicant has not presented such an alternative design, or indicated whether a final contract has been executed, and is not permitted to construct and operate such an alternative design by the approved PSD and Title V permits.

The additional operating scenario is not required to be submitted because it has been deemed to be "experimental."

Comment No. VII.54

Permit No. PSD-LA-751 violates § 165 of the Clean Air Act because it does not include an analysis of air quality impacts projected for the area as a result of growth associated with the proposed facility. If the air quality impact indicates the issuance of a PSD permit will consume at least 50% of any available annual increment or at least 80% of any short term increment, the owner or operator must also submit an analysis of any effects that the proposed project might have on the industrial and economic development of the area." This analysis must include "the effects that alternative siting or reduction of other emissions may have on the industrial and economic development of the area." Louisiana Guidance for Air Permitting Actions, p. 95. As discussed in the modeling comments above, aggregate emissions from the DRI-pig iron facility will consume 100% of the available increment for PM₁₀ and will cause violations of the NAAQS for NO₂, SO₂, PM₁₀ and PM_{2.5}. If Nucor were to construct only a DRI process, the facility likely would have a positive effect on industrial and economic growth in the area, but if Nucor constructs the pig iron process too, industrial and economic growth will come to a halt because all available increments will be consumed. The consumption of the increment will prevent construction or modification of other industrial and commercial sources in St. James Parish, to the detriment of Zen-Noh and other residents of St. James Parish. Nucor should be required to submit a detailed analysis of the inhibitory effect the DRI-pig iron facility will have on industrial and economic development in the area, which should include an analysis of the effect on industrial and economic development in St. James Parish if Nucor locates elsewhere or reduces emissions, for example by constructing only a DRI process.

LDEQ Response to Comment No. VII.54

Nucor has stated frequently that both of the facilities to be sited in St. James parish are part of a vertical integration strategy within the company, and that both the raw materials consumed and the products produced will be shipped to or from distant locations, primarily by the Mississippi River and connecting waterways. The tendency of these projects to drive additional heavy industrial projects is not supported.

The contention that a project should be rejected due to the consumption of increment is novel in LDEQ's experience, and the commenter provides no supporting precedent. LDEQ believes that the extension of §165 of the Clean Air Act to require facilities to submit an analysis detailing how the provisions of the Act will curtail economic activity in the State, and approve or reject a project on the basis of such future and uncertain economic predictions, is a concept outside of the authority granted by the CAA SIP process, and one more suited to political debate.

Comment No. VII.55

Permit No. PSD-LA-751 violates 42 U.S.C. § 7475(a) and (e) because the public has not been given an opportunity to review at least one year of continuous air quality monitoring data. PSD requires pre-construction air monitoring if modeled impacts exceed the levels specified in LAC 33:III.509.1.5. The air dispersion modeling shows that the NO_x, PM₁₀ and SO₂ emissions from the aggregate DRI-pig iron facility will exceed the PSD monitoring significance levels. LDEQ must require Nucor to perform both pre-construction and post-construction air monitoring for both PM₁₀ and SO₂, including the requirement to conduct one year of pre-application monitoring. *See* LAC 33:III.509.M. LDEQ must reconvene the public hearing after Nucor completes the pre-application air monitoring so that the public will have an opportunity to review and comment on the data at the hearing. *See* LAC 33:III.509.M.1.d; 42 U.S.C. § 7475(e)(2).

Moreover, Nucor has committed to undertaking the air quality monitoring. *See* EDMS Doc. 7725825. If Nucor had begun this monitoring in November 2008, when Zen-Noh first commented that preconstruction monitoring is required, or even in April 2010, when Zen-Noh again made this comment, the monitoring would be complete or nearly so. LDEQ should have required Nucor to conduct the modeling beginning in November 2008. There is no expediency in allowing Nucor to avoid this nondiscretionary statutory requirement, two years after Nucor could have begun the modeling, and after EPA has determined that NO₂ and SO₂ are harmful at concentrations that will be exceeded if the aggregate DRI-pig iron facility is constructed. Indeed, Nucor's own modeling indicates that the NO₂ air quality in St. James Parish may be harmful even without the addition of the Nucor sources. LDEQ should faithfully exercise its duties under the SIP and as public trustee for the environment and require Nucor to conduct at least one year of preconstruction air quality monitoring for all regulated NSR pollutants.

LDEQ Response to Comment No. VII.55

LAC 33:III.509.I.5. states:

The administrative authority may exempt a stationary source or modification from the requirements of Subsection M of this Section, with respect to monitoring for a particular pollutant, if:

- a. *The emissions increase of the pollutant from a new stationary source or the net emissions increase of the pollutant from a modification would cause, in any area, air quality impacts less than the following amounts:*

Carbon Monoxide	575 $\mu\text{g}/\text{m}^3$	8-hour average
Nitrogen Dioxide	14 $\mu\text{g}/\text{m}^3$	Annual average
Particulate Matter	10 $\mu\text{g}/\text{m}^3$ of PM_{10}	24-hour average
Sulfur Dioxide	13 $\mu\text{g}/\text{m}^3$	24-hour average
Ozone	No de minimis air quality level is provided for ozone. However, any net increase of 100 tons/year or more of volatile organic compounds or nitrogen oxides subject to PSD would require the performance of an ambient impact analysis including the gathering of ambient air quality data.	
Lead	0.1 $\mu\text{g}/\text{m}^3$	3-month average
Fluorides	0.25 $\mu\text{g}/\text{m}^3$	24-hour average
Total Reduced Sulfur	10 $\mu\text{g}/\text{m}^3$	1-hour average
Hydrogen Sulfide	0.2 $\mu\text{g}/\text{m}^3$	1-hour average
Reduced Sulfur Compounds	10 $\mu\text{g}/\text{m}^3$	1-hour average

Significance modeling was performed as part of the DRI application. The following results demonstrate that preconstruction monitoring is not required based on LAC 33:III.509.I.5. Since preconstruction monitoring was not required, these records are not available.

Pollutant	Averaging Period	Preliminary Screening Concentration ($\mu\text{g}/\text{m}^3$)	Significant Monitoring Concentration ($\mu\text{g}/\text{m}^3$)	Preconstruction Monitoring Required?
PM_{10}	24-hour	7.8	10	No
SO_2	24-hour	0.03	13	No
NO_x	Annual	0.46	14	No
CO	8-hour	11.5	575	No
Pb	3-month rolling average	0.001	0.1	No

Comment No. VII.56

Permit No. PSD-LA-751 violates §§ 160 and 165 of the Clean Air Act because the public has not been given the required opportunity for informed participation in the decision making process. LDEQ has violated state and federal law and deprived the public of the opportunity to review and provide meaningful comments on Nucor's DRI permit. Zen-Noh and the general public are entitled to the full opportunity to participate meaningfully in the permit process, under, among other things, Sections 160 and 165 of the Clean Air Act, Section 2018 of the Louisiana Environmental Quality Act and LDEQ regulations regarding the permitting of major sources.

The EQA requires the permit applicant to submit copies of the environmental assessment statement to the local government and local public library "[s]imultaneously with the submission of the statement to the department." La. Rev. Stat. § 30:2018.C. The permit

applicant is also required to notify the public, within 30 days after receiving notice that LDEQ has determined the application to be administratively complete, by publishing notice of administrative completeness in a major newspaper and submitting proof of publication to LDEQ. LAC 33:I.1505.A.5. Nucor submitted the DRI permit application on August 20, 2010. But, Nucor did not submit the environmental assessment statement for the DRI plant to the local government and public library until November 22, 2010 -- 94 days after Nucor submitted the application to LDEQ and only 2 days before LDEQ issued the draft permits for public notice.

In addition, LDEQ provided notice to Nucor that the permit application is administratively complete on August 31, 2010. Pursuant to LAC 33:I.1505.A, Nucor was required to publish notice of this determination and submit proof of publication to LDEQ no later than September 30, 2010. Nucor did not arrange to have the notice published until November 18, 2010 and did not submit proof of publication to LDEQ until November 22, 2010. *See* EDMS Doc. No. 7735159. Until that time, Zen-Noh and the public could not reasonably have known that LDEQ was processing the application. Without publication of this notice, Zen-Noh and the public reasonably would believe that the application was not complete and that significant changes could occur. By failing to comply with these public notice requirements, Nucor denied Zen-Noh and the public at least 53 days in which also to review the application and environmental assessment statement and to prepare comments.

In fact, Nucor made significant changes to the application throughout LDEQ's review and submitted several addendums, the last (so far as we know) of which was submitted on November 23, 2010--just one day before LDEQ issued the draft permits. Zen-Noh submitted a Freedom of Information Act ("FOIA") request to LDEQ for all documents associated with Nucor's DRI permit on September 7, 2010 and, on November 29, 2010, submitted a second request, this one specifically requesting all air quality modeling files submitted or generated in support of the DRI permit. LDEQ produced compact discs containing data files on about December 8, 2010, which according to LDEQ's representations contained the entire file associated with Nucor's DRI permit. However, Zen-Noh later discovered that a number of files were missing, including several important air quality modeling files. This additional data was not made available to until December 21, 2010, leaving Zen-Noh less than seven days to review before the public hearing.

The file that was made available to the public contains tens of thousands of pages of documents. As discussed above, the permits and applications are rife with inconsistencies -- some apparently introduced by Nucor, and others apparently introduced by the permit writers. These inconsistencies make review tedious and painstaking. It is certainly not unreasonable for the public to request, and LDEQ to grant, an extension of time to review the file and submit comments, particularly insofar as many inconsistencies appear to have been created by Nucor and LDEQ's haste to publish the draft permits. It should not be the public's job to police LDEQ's work.

LDEQ has a duty under the Clean Air Act to provide time for -- and obtain -- informed public participation in the decision making process. LDEQ also has a duty, as the public trustee for the environment, to take whatever time is necessary to carefully consider the environmental impacts of a major source like the aggregate DRI-pig iron facility, and in doing so to seek and take heed of the concerns raised by the major source's neighbors. LDEQ has not satisfied either duty.

LDEQ Response to Comment No. VII. 56

LDEQ has provided ample time for public comment and review, an amount of time exceeding the required 30 days from public notice of the draft permits. Additionally, given previous comments, the cited requests for information, and legal actions pertaining to a pending suit against LDEQ for the issuance of permits PSD-LA-740 and 2560-00281-V0, the commenter has clearly been aware of the DRI permitting process since it began.

Comment No. VII. 57

The DRI Permits violate Article IX, Section 1 of the Constitution of Louisiana and § 2018 of the Louisiana Environmental Quality Act because LDEQ failed to perform its duties as public trustee of the environment. Nucor did not submit an environmental assessment statement because Nucor erroneously characterized the pig iron modifications as "minor." As discussed elsewhere in these comments, constructing SCR for the pig iron sources will cause a significant increase in emissions of sulfuric acid mist, ammonia and naphthalene. These increases cannot be permitted as minor modifications; indeed, the increase in sulfuric acid mist emissions requires a preconstruction PSD permit. Under La. Rev. Stat. § 30:2018, an environmental assessment statement must be submitted for any permit to construct a major source of air emissions or any major modification of an existing permit for a major source. Nucor should be required to complete the IT Questions for the pig iron modification and LDEQ should complete an environmental assessment statement.

In issuing a permit, LDEQ "is required to make basic findings supported by evidence and ultimate findings which flow rationally from the basic findings" and to detail the connection between the evidence and the ultimate decision to issue the permit. *Save Ourselves, Inc. v. Louisiana Env'tl. Control Comm.*, 452 So. 2d 1152, 1159 (La. 1984). Failing to do so is an abuse of LDEQ's discretion and position as public trustee. *In re E.I. du Pont de Nemours & Co.*, 674 So. 2d 1007, 1011 (La. App. 1996); La. Const. art. IX § 1; La. Rev. Stat. § 30:2014.A.4. As the public trustee, LDEQ must balance the interests of the environment and public before issuing permits. *Save Ourselves, Inc. v. Louisiana Env'tl. Control Comm.*, 452 So. 2d 1152 (La. 1984).

In comments submitted on the Nucor's original Pig Iron permit, Zen-Noh noted that LDEQ should require Nucor to evaluate the use of direct reduction iron ("DRI") for the manufacture of pig iron, as an inherently lower polluting process. *See* Zen-Noh Comments submitted Nov. 24, 2008, Comment # 31 ("LDEQ and Nucor should have considered alternative and innovative technologies for the control of emissions from the coke ovens, including the direct reduction iron ("DRI") and COREX® processes, which manufacture pig iron without the use of coke -- and hence eliminate coke oven, coke charging and coke pushing emissions entirely."); *Id.*, Comment 84 ("Nucor's evaluation of alternative processes, in particular the DRI process, places Nucor's economic return on a pedestal well above the protection of the environment. There is no question that, by eliminating coke ovens and blast furnaces, the DRI process is significantly more environmentally friendly than the old-school pig iron manufacturing process proposed by Nucor. Nucor operates a large DRI iron facility on Trinidad and can easily prepare an objective analysis of the cost-effectiveness of the DRI process compared to the emissions from the blast furnace process. There is a good chance that the DRI process will result in orders of magnitude lower emissions at little to no increased cost.") LDEQ responded that utilizing DRI technology would not be possible for the facility because DRI facilities produce sponge iron, not pig iron, and cannot produce more than 800,000 tons per year at that. *See* LDEQ Response to Comments, EDMS # 47485821, at 118 of 444. However, as evidenced by the fact that Nucor has now altered its proposed facility to incorporate the

use of DRI into its production process, it is possible-and even practical-for the facility to utilize DRI technology. LDEQ's failure to require Nucor to incorporate this technologically feasible lower emitting process demonstrates that it is not carrying out its duties under the CAA and is abusing its discretion and position as public trustee.

LDEQ Response to Comment No. VII.57

The commenter asserts that the DRI permit violates the Constitution of Louisiana and the Louisiana Environmental Quality Act because the pig iron permit modification should be classified as a significant modification. The commenter is in error; emissions of all pollutants associated with the pig iron permit, except ammonia, were reduced or remained the same as represented in the permit application. Ammonia is a class III toxic air pollutant, for which increases do not require public notice under LAC 33:III.5107.D.2. As such, emissions increases of ammonia do not trigger a significant modification of the permit. No new federal rule programs, such as NESHAP or NSPS, became applicable to the pig iron facility, and significant modification procedures are not required on this basis. The pig iron plant permit modification is a minor modification under LAC 33:III.525, for which an environmental assessment statement is not required.

In the same discussion, the commenter cites previous comments, on Nucor's Pig Iron permit, that LDEQ should require Nucor to evaluate DRI as an alternative technology. The commenter considers both actions a failure in LDEQ's duties. As discussed in previous responses to comments, LDEQ understands that DRI and pig iron are materially different products that are not interchangeable in their end uses, and are manufactured by significantly different technologies. It is not a case where a substantially identical product may be made by different processes, with different environmental impacts. LDEQ does not consider its role to be one of dictating to facilities what product should be made at their facilities, or issuing statements of preference for one over another. New facilities proposed for construction must stand on their own merit. LDEQ exercises its responsibilities as a public trustee by providing environmental regulatory oversight of industrial facilities, and issues permits on the basis of the requirements necessary to comply with environmental statutes, regulations and health standards established by federal and state authorities.

Comment No. VII.58

Permit No. 3086-V0 violates Title V of the Clean Air Act because it fails to incorporate all specific conditions from and is inconsistent with the DRI PSD permit. The DRI Part 70 permit fails to include all Specific Conditions from the DRI PSD permit as required by law and in several instances is inconsistent with the draft PSD Permit. This undermines the purpose of a Title V permit as a legally enforceable document designed to improve compliance by clarifying what facilities must do to control air pollution.

The Louisiana Administrative Code ("LAC") at 33:III.501.C.6 requires LDEQ to include in each permit "sufficient terms and conditions to ensure compliance with all state and federally applicable air quality requirements and standards..." The terms "federally applicable requirement" includes any term or condition of a PSD permit. *See* LAC 33:III.502.A. This rule requires not only that a Title V permit include emission limitations and standards, including operation requirements and limitations that assure compliance with all applicable requirements, but also that the permit "specify and reference the origin of and authority for each term or condition, and identify any difference in form as compared to the applicable requirement upon which the term or condition is based." Instead, the draft Title V Permit includes Specific Requirement #294: "Comply with the requirements of PSD-LA-751. This permit includes provisions of the Prevention of Significant Deterioration (PSD) review (sic) from Permit PSD-LA- 751.

This incorporation by reference defeats one of the primary purposes of the Title V program, which is "to enable the source, states, EP A, and the public to better understand the requirements to which the source is subject, and whether source is meeting those requirement." *See* 57 FR 32,250/51 (July 21, 1992). Incorporation by reference in permits is only appropriate under limited circumstances, such as test method procedures, inspection and maintenance plans, and calculation methods, and when it results in an unambiguous permit. Here, incorporation by reference of some PSD conditions but not others coupled with undocumented modification of conditions when transferred makes it difficult, if not impossible, for the public to know the precise requirements of the permit, thus defeating the central purpose of the Title V program to improve accountability and enforcement. *See* Memorandum from Lydia N. Wegman, Deputy Director, Office of Air Quality Planning and Standards, to Various Directors, Re: White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program, March 5, 1996, p. 40 ("On the other hand, it is generally not acceptable to use a combination of referencing certain provisions of an applicable requirement while paraphrasing other provisions of that same applicable requirement."). Any changes between the way a specific condition is described in the PSD permit and the way it appears in the Part 70 permit, for example changing from English to metric units, must be clearly documented in the record, but here they were not.

The necessary level of detail required in a Part 70 Permit is guided by section 504(a) and (c) of the CAA and corresponding provisions at 40 CFR 70.6(a)(1) and (3). At a minimum, EPA expects that Title V Permits will explicitly state all emission limitations and operational requirements for all applicable emission units at a facility. *Id.* The EPA has remanded Title V permits that cross-reference the PSD permits in their entirety, as here. *See In the Matter of Citgo Refining and Chemicals Company L.P., West Plant, Corpus Christi, Texas*, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition Number VI-2007-01, May 28, 2009, pp. 9-11 ("Moreover, the title V permit crosses references the PSD permit in their entirety. Thus EPA grants the petition on this issue."). *In the Matter of Tesoro Refining and Marketing Co., Martinez, California Facility*, Petition No. IX 2004-6, Order Granting in Part and Denying in Part A Petition for Objection to Permit, Petition No. IX-2004-6, pp. 8-9.

Table I shows a summary of the BACT determinations as summarized in the draft PSD Permit Briefing Sheet, Specific Conditions for individual emission units, and the corresponding Part 70 permit Specific Requirements. This table demonstrates that all of the PSD Specific Conditions were not carried over into the DRI Part 70 permit, and, in some instances, were modified, without any documentation. Thus, incorporation by reference creates many ambiguities.

See Tables Pages 114-119 of Zen-Noh comments

This summary shows that there are many instances in which: (1) PSD conditions were not carried over into the Title V Permit; (2) there are undocumented changes between the PSD and Title V conditions, for instance, a change in units or the numerical value of the limit; and (3) there are many cases in which the control option determined as BACT is not stated in the Title V Permit. Therefore, the draft Title V Permit must be revised to reflect the BACT determinations, deviations documented and emission limits for all units specified in the draft PSD Permit and recirculated for public review and comment.

LDEQ Response to Comment No. VII.58

The Title V permit includes requirements for demonstrating initial and ongoing compliance with the

terms of the PSD permit. The specific requirement that calls for compliance with the PSD permit as a whole does not negate these facts. The requirement is included to make clear that the PSD permit is not superseded by the Title V permit, and conditions or requirements made explicit in the PSD permit may be enforced through the Title V permit. The assertion that this requirement creates ambiguities is not supportable, since the applicant must comply with the requirements of both permits. This practice is simply sound legal practice, and it should be noted that the commenter has included similar incorporation by reference clauses in virtually every submittal made to LDEQ regarding this, and previous, permitting actions.

Comment No. VII.59

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for iron oxide storage and handling (DRI-101/201, DRI-102/DRI-202, DRI-105/DRI-205) and does not impose conditions necessary to assure compliance with BACT. As noted above, PSD permits should include specific conditions requiring a source to monitor emissions and operating parameters to assure continuous emission reductions and compliance with BACT. These monitoring and recordkeeping requirements are "applicable requirements" that must be incorporated into the Part 70 permit. If a PSD permit for some reason does not include specific conditions necessary to assure compliance, Title V requires the permitting agency to develop and include such conditions in the source's Part 70 permit.

The DRI Part 70 permit includes two types of applicable requirements for DRI-101/201, DRI-102/202, and DRI-105/205: (1) a PM₁₀ concentration in gr/dscf (Specific Requirements #25,44, #60, #173, #192, #218) and (2) PM₁₀ emission rates in lb/hr and tons/yr in the Emission Rates for Criteria Pollutants table. The Specific Requirements do not assure continuous compliance with these applicable requirements.

First, the permit does not require any testing to determine compliance with the BACT emission limitation of 0.002 gr/dscf, any of the emission rates that were calculated from it, or the \geq 99.5% BACT PM₁₀ removal efficiency for the baghouse. The LDEQ has failed to explain why no testing is required to determine compliance for DRI-101/201, DRI-102/202, and DRI-105/205.

Instead, the permit requires monitoring of various fabric filter baghouse operational parameters, such as pressure drop, visible emissions, and unidentified operating parameters, etc. The permit record does not explain anywhere how this monitoring is sufficient to assure the baghouse is achieving the BACT emission limitation of 0.002 gr/dscf and other applicable requirements, such as 99.5% PM₁₀ control. The unstated assumption is that if emissions are directed to a baghouse and the baghouse is functioning properly and emissions are not visible, the emissions will be below the gr/dscf and lb/hr limits and the baghouse will remove 99.5% of the PM₁₀. There is no demonstration that this assumption is true. Many Title V permits have been remanded for similar failures. *See, e.g., In the Matter of Wisconsin Public Service Corporation's JP Pulliam Power Plant*, Order Granting Petition for Objection to Permit, Petition Number V-2009-01, Section III; *In the Matter of Citgo Refining and Chemicals Company L.P. West Plant, Corpus Cristi*, Petition Number VI-VI-2007-01, May 28, 2009, pp. 4-8; *In the Matter of The Premcor Refining Group Inc. Port Arthur, Texas*, Order Partially granting and Partially Denying the Petition for Objection to Permit, Petition Number VI-2007-2, February 7, 2008.

Second, the permit does not set any limitations or acceptable operating ranges for all of the indicators: visible emissions (Specific Requirements #15, 23, 34, 56, 163, 170, 184,

210, 216), unspecified operational data (Specific Requirements #22, 24, 57, 58, 59, 168, 169, 172, 187, 188, 191, 214, 215, 217). The differential pressure range is stipulated as >3.5 to <11.5 inches w.c.: (Specific Requirements #19, 38, 53, 167, 186, 212). This is a very broad range that is unsupported in the record. The LDEQ has not explained how such a wide range could assure compliance with the applicable requirements. Title V Permits have been remanded for failure to set indicator ranges.

Third, accurate and precise monitoring of baghouse operation is essential to assure compliance. A recent study, for example, shows that 15% of the gas bypasses the baghouse and flows out the stack without being cleaned when only one bag fails. When 10% of the bags are broken, greater than 90% of the gas is untreated. Assuming a design control efficiency of 99.9%, a single broken bag reduces baghouse efficiency to about 85% and the outlet dust loading is about 150 times higher than design. *See Wenjun Quin and others, Prediction of Particulate Loading in Exhaust from Fabric Filter Baghouses with One or More Failed Bags, J. Air & Waste Manage. Assoc., v. 56, 2006, p. 1179.* The indicators used for the baghouse include unspecified operational data, but the only baghouse parameter mentioned is differential pressure measured by a pressure gauge. It is well known that pressure-drop information cannot be interpreted properly unless the flow rate is known, which is not monitored under the DRI Part 70 permit. *See McKenna et al. 2008, pp. 129-130.*

The method used to measure pressure drop is not specified. The pressure will be measured by "pressure drop instrument" (Specific Requirement #20, 41), which is vague. Will the pressure be measured between the inlet and outlet of the baghouse or at the inlet and outlet of each compartment? Inlet-to-outlet pressure drop across baghouses cannot detect leaks in individual bags or even several individual bags. This requires the use of a much more effective bag leak detection system than differential pressure gauges. These are commonly specified for baghouse monitoring in PSD permits. This is the same type of requirement that is included in the NESHAP for secondary lead smelters, 40 CFR 63, Subpart X, in order to ensure continuous compliance with lead emission limits. Over time, pressure-sensing lines become clogged with dust or the gauge becomes unreadable due to dust accumulation. Thus, maintenance is required to assure pressure measuring instrumentation is accurate.

Other unspecified operational data will be monitored by "technically sound method" which is not specified (Specific Requirements #22, 39, 46, 59, 169, 187, 217). Such vague references are unenforceable.

Fourth, compliance can only be determined if the concentration of PM₁₀ is directly measured in the exhaust gases from the baghouse. The DRI Part 70 permit requires measurement of pressure drop and visible emissions but these reveal no information about particulate concentrations expressed in gr/dscf or emission rates expressed in lb/hr and ton/yr, unless studies are conducted to establish a relationship between pressure drop and concentration and a specific limitation or range is established to assure the underlying limit is continuously met. Thus, the proffered BACT limits are not enforceable as a practical matter.

Fifth, it is feasible and necessary to measure PM₁₀ in the baghouse exhaust gases. The LDEQ has not explained in the permit record why direct testing for gr/dscf, control efficiency, and emission rates is not required and how the Part 70 permit's monitoring of baghouse operation and visible emissions assures compliance with the PM₁₀ emission limitations. As noted above, many Title V permits have been remanded for similar failures. A change in the origin or composition of iron ore or handling procedures, for

example, could result in PM₁₀ emissions that are chemically and physically distinctive and would thus be removed to a lesser degree by the baghouse than the material initially used to establish operating ranges.

Sixth, the BACT emission limitation is not practically enforceable as it does not include any averaging time. The stringency of an emission limit is a function of both the magnitude and averaging time. Thus, averaging times must be required. As stated, absent an averaging time, it applies instantaneously. The specific requirements do not allow instantaneous compliance.

LDEQ Response to Comment No. VII.59

LDEQ has required the applicant to install fabric filters certified by the manufacturer to control emissions of PM₁₀ and PM_{2.5} at the minimum efficiency of 99.5% determined as BACT for these sources. These certifications are then supported by adequate parametric monitoring to assure compliance with the permitted limits, using parameter ranges determined to demonstrate compliance. The use of parametric monitoring techniques is commonplace in environmental permits issued in Louisiana, and throughout the United States. Assertions to the contrary are wholly without merit.

LDEQ has included parametric and visual monitoring requirements sufficient to detect the failure of filter bags on a daily basis. Additionally, the permit requires the timely correction of failed filter bags within 3 days of detection; failure to correct a malfunction of this type would be a violation of the permit. Direct and continuous measurement of PM₁₀ from this source is not warranted, as the emission characteristics of baghouses and filter vents are well understood and stable at designed operating rates. LDEQ does not specify the type, make or model of specific measurement instruments (e.g. pressure drop) without a firm basis for doing so, and such a basis does not exist in the case of a pressure drop meter across a filter, at these sources. The facility operator subject to the Title V permit has the responsibility to certify compliance with the pressure drop measurement requirement, and a systematic failure to maintain measurement equipment would place such certifications in jeopardy, carrying the potential for criminal enforcement.

Comment No. VII.60

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for the iron oxide coating bin (DRI-103/203). The DRI Part 70 permit includes three types of applicable requirements for sources DRI-103/203: (1) a PM₁₀ concentration in gr/dscf (Specific Requirements #50, #198); (2) a control efficiency (Specific Requirements #45, #193) and (3) PM₁₀ emission rates in lb/hr and tons/yr in the Emission Rates for Criteria Pollutants table. The monitoring provisions do not ensure compliance with these applicable requirements.

First, the permit does not require any testing to determine compliance with the BACT emission limitation of ≤ 0.02 gr/dscf, any of the emission rates that were calculated from it, or the 99.5% PM₁₀ removal efficiency for the baghouse. LDEQ must -- but failed to -- explain why testing of DRI-103/203 is not required.

Instead, the Part 70 permit requires monitoring of various unspecified fabric filter baghouse operational parameters (Specific Requirements #46-48, 195-197) and visibility (Specific Requirements #49, 194). The unstated assumption is that if emissions are directed to a baghouse and the baghouse is functioning *properly* and emissions are not visible, the emissions *will* be *below* the gr/dscf and lb/hr limits and the baghouse will remove 99.5% of the PM₁₀. The permit record does not explain how this monitoring is

sufficient to assure the baghouse is achieving the BACT emission limitation of 0.02 gr/dscf and other applicable requirements, such as 99.5% PM₁₀ control.

Second, the DRI Part 70 permit does not set any limitations or acceptable operating ranges for any of the unidentified indicators. The lack of limitations on the operational parameters creates ambiguity. Specific Requirement #194, for example, requires that if visible emissions are observed, the baghouse filter is to be returned to compliance as expeditiously as practicable. However, how is one to determine when the baghouse is returned to compliance if the emission limitations themselves are never measured? A dust loading of 0.02 gr/dscf cannot be visually detected. LDEQ has not explained in the permit record why testing of gr/dscf, lb/hr, and control efficiency are not required and how the Part 70 permit's monitoring of baghouse operational parameters assure compliance with the PM₁₀ emission limitations. As cited above, many Title V permits have been remanded for similar failures.

Finally, the BACT emission limitation is not practically enforceable as it does not include any averaging time. The stringency of an emission limit is a function of both the magnitude and averaging time. Thus, averaging times must be required.

LDEQ Response to Comment No. VII.60

Comment No. VII. 60 is substantially the same as Comment No. VII. 59, but directed at the Iron Oxide Coating Bin. See LDEQ's Response to Comment No. VII. 59 for our response to this comment.

Comment No. VII.61

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for iron oxide fines storage and handling (DRI-104/204). The BACT determination in the Preliminary Determination Summary of the DRI PSD permit concludes that BACT for PM₁₀ and PM_{2.5} for iron oxide fines storage and handling is: (1) application of a chemical surface stabilizer on the iron oxide storage piles (95% control efficiency); (2) use of water sprays locally to control dust from stacking, reclaiming, and pile maintenance (90% control efficiency); and (3) minimizing handling (50% control efficiency). The Part 70 permit, in contrast, includes Specific Requirements #52 and #199, which provide that BACT for PM₁₀ is only "implementation of wet suppression of dust generating sources by water sprays at each storage pile. Thus, the DRI Part 70 permit fails to require all applicable requirements of the PSD permit.

In addition, Specific Requirements #352 and #199 are ambiguous as they can be interpreted and implemented in many different ways and are not effective unless reworded so they capture the assumptions used in the emission calculations, including limits on control efficiency, number and type of vehicles, silt content, and moisture content and require recordkeeping and reporting to assure these underlying assumptions are achieved in practice.

Furthermore, the DRI PSD permit does not require any testing or recordkeeping to assure that BACT is met. The emission calculations are based on many assumptions including throughputs, silt contents, dozer miles per day, pile maintenance hours, etc. There is no monitoring or recordkeeping for any of these assumptions. How frequently must water sprays be used to assure the control efficiencies assumed in the emission calculations? How much water must be applied each time and under what conditions? What must be done to assure chemical application reduces wind erosion by 95%? Where is the

recordkeeping for the number and types of trucks and heavy equipment assumed in the emission calculations? The LDEQ has not explained why no testing of DRI-104/204 is required.

Last, Specific Requirement #51 appears to be an error. It specifies a limitation of TSP ≤ 0.6 lb/MMBtu of heat input (complying using sweet natural gas as fuel). Natural gas is not used at DRI 104/204. This condition appears to have been erroneously included and should be deleted.

LDEQ Response to Comment No. VII.61

BACT for control of fugitive dust emissions from Iron Oxide Fines Storage and Handling is described in detail in the PSD permit, which is referenced in its entirety by Specific Requirement No. 294. Additionally, requirements to apply chemical surface stabilizers, and to take steps to limit fugitive emissions from vehicle traffic are included with the Nucor Steel Louisiana Dust Management Plan. Adherence to the Dust Management Plan is a condition of the Title V permit. It is incumbent upon the operator to certify compliance with the operational and emission limitations referenced by or contained within the Title V permit.

Comment No. VII.62

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for product fines briquetting (DRI- 117). The DRI Part 70 permit includes two types of applicable requirements for DRI- 118: (1) a PM₁₀ concentration in gr/dscf (Specific Requirements #145) and (2) PM₁₀ emission rates in lb/hr and tons/yr in the Emission Rates for Criteria Pollutants table. The permit requires only a single stack test for PM₁₀ /PM_{2.5} over the life of the facility coupled with measuring either the pressure drop or flow rate of the scrubber to satisfy "the PSD limitation" in Specific Requirement #138, but fails to identify which limitation is the target.

First, the permit record does not explain anywhere how one stack test over the life of the facility and scrubber flow once every four hours (or pressure monitoring at an undetermined frequency) are sufficient to assure the scrubber is continuously achieving 99% PM₁₀ control and meeting hourly PM₁₀ emission rates used in the source impact analyses. The unstated assumption is that if emissions are directed to a scrubber and the scrubber is functioning properly, the scrubber will achieve 99% PM₁₀ removal and meet the lb/hr and other emission limitations. However, this has not been demonstrated, and absent a demonstration, one stack test over the life of the facility is certainly not adequate to demonstrate continuous compliance.

Flow monitoring reveals no information about PM₁₀ concentrations expressed in gr/dscf nor lb/MMBtu or PM₁₀ emission rates expressed in lb/hr and ton/yr, unless studies are conducted to establish a statistically valid relationship between flow rate and these emission metrics. Thus, Specific Requirement #145 should require a study to demonstrate a relationship between the flow/pressure and the subject applicable requirements. Otherwise, the proffered BACT PM₁₀ limit is not enforceable as a practical matter and the draft Title Permit does not assure compliance with the applicable requirements.

Any such relationship would only be valid for the conditions under which it was developed. If the iron ore composition changed or process operating conditions changed, any such relationship would change. The permits should be revised to require at least annual stack testing to measure particulate emission limitations expressed as gr/ dscf,

lb/MMBtu, lb/hr and ton/yr to test the validity of the relationship and to directly determine compliance. The study to establish the indicator relationship should be repeated every 5 years or whenever a change occurs that would affect scrubber emissions.

As noted above, many Title V permits have been remanded for similar failures. A change in the origin or composition of iron ore or the DRI product, for example, could result in PM₁₀ emissions that are chemically and physically distinctive and would thus be removed to a lesser degree than the material initially used to establish operating ranges.

Second, the indicator monitoring ranges are determined after the facility is constructed and operating. The Specific Requirements do not state that exceedances of these future thresholds would be a violation of the underlying BACT emission limit nor require any demonstration of a correlation between flow or pressure and PM₁₀ /PM_{2.5} emissions. Thus, the proffered BACT limit is not enforceable as a practical matter.

LDEQ Response to Comment No. VII.62

Although the title of this comment states that it is directed toward emissions from source DRI-117, Product Fines Briquetteing, the body of the comment mentions only source DRI-118, Product Loading. Due to the duplicative nature of Comment Nos. 62 and 63, LDEQ has assumed that the title of Comment No. VII. 62, naming source DRI-117, is correct, and the body of the comment has merely been copied and pasted from Comment No. VII. 63, resulting in the inconsistency. We have responded to the comment on this basis.

LDEQ has required performance tests of sources subject to a technology-based BACT determination, such as a high-energy scrubber, to prove the efficacy of these devices. These tests are then supported by adequate parametric monitoring to assure compliance with the permitted limits, using parameter ranges determined to demonstrate compliance by the test, such as pressure drop or scrubber liquid flow rate. The use of parametric monitoring techniques is commonplace in environmental permits issued in Louisiana, and throughout the United States. The established parametric monitoring is adequate for the proposed conditions specified in the permit application. Deviations from the permitted conditions will require additional LDEQ approval through an appropriate permitting mechanism.

The BACT determination establishes the control technology (scrubber), the emission limit and the **method** by which compliance will be determined (a stack test that will establish parametric monitoring, namely the pressure drop). The exact range for the parametric monitoring can not be established preconstruction. (It is dependant upon the facility actually constructed.) This satisfies the requirements for a PSD permit.

Performance testing must be conducted at the process conditions which would be expected to generate the maximum emissions, which is not necessarily at the highest processing capacity for any given source. The commenter speculates that the results of such test would become invalid “if the iron ore composition changed or process operating conditions change,” but fails to support the contention that such changes would invalidate performance test results required to be obtained under worst-case operating conditions.

The specified testing requirements are appropriate to ensure compliance with the permit limits during the five year term of the permit. The validity of these test data will be considered at the review process of the permit renewal.

Comment No. VII.63

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for product loading (DRI-118). The DRI Part 70 permit includes two types of applicable requirements for DRI-118: (1) a control efficiency (Specific Requirement # 154) and (2) PM₁₀ emission rates in lb/hr and tons/yr in the Emission Rates for Criteria Pollutants table. Compliance is determined by indicator monitoring without any direct testing. This scheme does not ensure compliance with these applicable requirements.

First, the draft permits do not require any testing to determine compliance with the BACT limitation of 90% control efficiency for the scrubber (Specific Requirement #154) and PM₁₀ emission rates in lb/hr and ton/yr. The permit record does not explain anywhere how no direct testing is sufficient to assure the applicable requirements are met.

Instead, the DRI Part 70 permit requires Standard Operating Procedures to be developed to control PM₁₀ emissions from DRI barge loading (Specific Requirement #146). These Operating Procedures can and should be identified in the Title V Permit, but will be developed in the future. Further, the permit requires determining target flow rates or pressure drop required to satisfy "the PSD limitation," presumably the BACT limit, but does not identify the limitation (Specific Requirement #147). One must guess that it is PM₁₀ and speculate whether it covers just the 90% control efficiency limit or also includes the lb/hr and ton/yr limits.

Second, the permit record does not explain anywhere how standard operating procedures and flow and pressure monitoring are sufficient to assure the scrubber is achieving 90% PM₁₀ control and meeting PM₁₀ emission rates used in the source impact analyses. The Permit does not disclose the purpose of this indicator monitoring, but presumably, it is being used as a surrogate for PM₁₀ under the assumption that if emissions are directed to a scrubber and the scrubber is functioning properly, the scrubber will achieve 99% PM₁₀ removal and meet the control efficiency and lb/hr emission limitations. Therefore, the Specific Requirements should state that exceedances of these future thresholds would be a violation of the underlying BACT emission limit. As noted above, many Title V permits have been remanded for similar failures. A change in the origin or composition of iron ore or the DRI product, for example, could result in PM₁₀ emissions that are chemically and physically distinctive and would thus be removed to a lesser degree than the material initially used to establish operating ranges.

Third, the conditions establishing these procedures and thresholds also do not require any study to demonstrate a relationship between the procedures, flow, pressure, and scrubber control efficiency or PM₁₀ /PM_{2.5} emissions. Thus, the proffered BACT limit(s) is not enforceable as a practical matter and the Part 70 permit does not assure compliance with the applicable requirements.

Any such relationship determined from a future study would only be valid for the conditions under which it was developed. If the iron ore composition changed or process operating conditions changed, any such relationship would change. The permits should be revised to require at least annual stack testing to measure particulate emission limitations expressed as gr/dscf, lb/MMBtu, lb/hr and ton/yr to test the validity of the relationship and to directly determine compliance. The study to establish the indicator relationship should be repeated every 5 years or whenever a change occurs that would affect scrubber emissions.

Fourth, Specific Requirement #149 requires developing daily average ranges of acceptable pressure drop or flow rate of the scrubber. However, other Specific

Requirements for DRI-118 only require monitoring and reporting of flow rate (Specific Requirement #151). No monitoring or reporting is required for pressure drop.

Fifth, the BACT PM₁₀ emission limitation reflected in the Part 70 permit contains no averaging time and thus is not practically enforceable.

Sixth, the DRI Part 70 permit contains a condition that requires loading operations to be operated in such a manner that "the fugitive emissions created by such operations are not a nuisance to the public." (Specific Requirement #150). This condition is vague, ambiguous, and practically unenforceable. The term "nuisance to the public" should be defined in concrete measurable terms, e.g., contamination of adjacent property, an odor threshold, a certain number of complaints, visible emissions, dust loading levels at adjacent properties, noise levels, etc. Acceptable and unacceptable loading operating conditions should be specifically identified. See, e.g., *In the Matter of the Premcor Refining Group, Inc. Port Arthur, Texas*, Petition Number VI-2007-2, May 28, 2009, p. 22; *In the Matter of Midwest Generation (Joliet Generating Station)*, Petition No. V-2004-3, June 24, 2005, p. 59. Further, the condition does not indicate what actions are to be taken if nuisance occurs. The permit should be modified to require mitigation of the nuisance conditions within 24 hours of detection.

Last, the only recordkeeping and reporting is for flow rate (Specific Requirements # 152, #153). The DRI Part 70 permit does not require any additional recordkeeping and reporting for other conditions, such as if the facility has complied with the Standard Operating Procedures (Specific Requirement #146), whether barge loading spouts have been positioned below the hatch opening when loading (Specific Requirements #147), whether tarpaulins were used during all ship loading operations (Specific Requirements #149), and whether any nuisance issues occurred (Specific Requirement #150). The absence of any recordkeeping and reporting for these conditions makes them unenforceable as a practical matter.

LDEQ Response to Comment No. VII.63

Portions of this comment are substantially the same as Comment No. VII. 62. Please see LDEQ Response to Comment No. VII. 62 for our response to aspects of this comment not addressed directly below.

Comment No. VII.64

Permit No. 3086-VO violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for the cooling towers (DRI- 113/213, DRI-114/214). The DRI Part 70 permit notes that compliance with BACT for this source can be determined based on measured IDS, "the design cooling tower circulating water rate (as installed)" and "a percent drift of 0.0005%. However, the Part 70 permit does not contain any limit on the circulating water rate itself, allowing the "installed rate," or any requirement to monitor and report it. The Specific Requirements imply a calculation to determine lb/hr emissions from the cooling towers, but do not explain how these three parameters limit emissions or what to do with them once they are collected. They should be used to calculate the PM₁₀ /PM_{2.5} emission rates in lb/hr. The Part 70 permit must be modified to clearly specify the procedure for calculating PM₁₀ /PM_{2.5} emissions from the cooling tower. The permit also should be modified to include PM₁₀ /PM_{2.5} BACT emission rates in lb/hr as used in the source impact analyses, to specify the maximum allowed circulating water rate, as assumed in the emission calculations, to require drift testing every five years, and monitoring and recordkeeping for all cooling tower

variables.

Fourth, the emission calculations implementing the BACT analysis go a step further than addressed in the draft permits by assuming that only 14.9% of the drift, calculated from the TDS content, drift rate, and circulating water flow rate, is PM_{10} and $PM_{2.5}$. There is nothing in the draft permits that restricts PM_{10} and $PM_{2.5}$ emissions from the cooling towers to only 14.9% of the drift (which is calculated from the circulating water rate, TDS, drift efficiency) nor any way to test for this fraction. The standard method for calculating cooling tower PM_{10} emissions assumes that 100% of the drift is PM_{10} . In fact, actual measurements using cascade impactors conclusively demonstrate that cooling tower drift is 100% PM_{10} . See G. Israelson, N. Stich, and T. Weast, Comparison of Cooling Tower Mineral Mass Emissions by Isokinetic EPA Method 13A and Heated Cascade Impactor Tests, Cooling Tower Institute Paper No. TP91 12, 1991 and Thomas E. Weast and Nicholas M. Stich, Reduction of Cooling Tower PM_{10} Emissions Due to Drift Eliminator Modifications at a Chemical Refining Plant, Cooling Tower Institute Paper No. TP92-10, 1992. The researchers conducting these measurements concluded: "there is sufficient information from the first set of cascade impactor tests to support the conclusion that the drift emitted from the cooling towers consists of water droplets that are so small that when they dry, the remaining solid particulates are all PM_{10} . Thus, the cooling tower emissions that were used in the air quality analysis are underestimated and, consequently, impacts on air quality are underestimated. When this correction is made, $PM_{10}/PM_{2.5}$ emissions from the cooling towers increase from 0.11 lb/hr to 0.74 lb/hr.

LDEQ Response to Comment No. VII.64

The variable used to calculate emissions from the cooling tower are cooling water recirculation rate, total dissolved solids (TDS) content, and percent drift rate. LDEQ has required that these variables be tested, in the case of cooling water recirculation rate and TDS content, or designed and maintained to the level determined as BACT, in the case of mist eliminators. These factors are used to determine compliance, and LDEQ will not accept a demonstration of compliance different from the methods used in the emission calculations without prior review and approval.

LDEQ reviewed the basis document provided by the applicant, *Calculating Realistic PM_{10} Emissions from Cooling Towers*, Greystone Environmental Consultants, Inc., 2002, and found the basis for particle size distribution calculations from the cooling towers to be reasonable and acceptable.

Comment No. VII.65

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for NO_x emissions from the package boilers (DRI-109/DRI-209). The Preliminary Determination Summary concludes that BACT for NO_x for the package boilers is the installation of low NO_x burners combined with SCR. The DRI PSD permit establishes a NO_x BACT limit of 0.00324 lb/MMBtu, which is incorporated into the DRI Part 70 permit. The Part 70 permit specifies that this limit be achieved using low NO_x burners and SCR at a minimum of 90% control efficiency. 156 This limit is converted into 0.85 lb/hr average and 0.94 lb/hr maximum emission rates in the "Emission Rates for Criteria Pollutants" table in the draft Title V Permit. The maximum hourly emission rate was used in the air quality modeling.

The compliance provisions for the NO_x BACT limit are not specifically identified in the DRI Part 70 permit. Presumably, Specific Requirements #95 and #251 are the NO_x BACT compliance provisions as nothing else requires NO_x testing. These conditions

require a single stack test over the entire life of the facility. This is not adequate to assure compliance with the terms and conditions of the permit.

A Title V permit must contain sufficient monitoring to assure compliance with the applicable requirements, which includes BACT and protection of the 1-hour ambient air quality standard. The NO_x emissions from natural gas fired boilers that rely on low NO_x burners and SCR to meet BACT emissions limits are variable and can range over an order of magnitude. We are not aware of any alternative methods) to a NO_x CEMS that can provide sufficient reliable and timely information to determine compliance with a NO_x emission limit for a combustion source equipped with low NO_x burners and an SCR. The Part 70 permit requires monitoring of fuel use. However, this only allows one to confirm that the boilers are burning natural gas, not that they complying with emission limit in lb/hr and ton/yr based on low NO_x burners and SCR. A NO_x CEMS is technically feasible and is widely used at similar facilities and should be required for the package boilers.

The DRI Part 70 permit specifies the averaging time as a "three one-hour test average." This does not assure compliance with the 'emission rates included in the source impact analysis. A 3-hour averaging time can mask shorter-term, 1-hour emission spikes, obscuring violations. The averaging time must be consistent with the I-hour NO_x. Thus, the permit should be modified to express the NO_x emission limit for the package boilers as a I-hour average based on the average of shorter-term measurements, such as recorded by a CEMS.

Last, an SCR converts some of the SO₂ in the exhaust gases into sulfur trioxide ("SO₃") which exits the stack as sulfuric acid mist, a PSD pollutant that was not evaluated for PSD applicability in the DRI Application. Further, the resulting sulfuric acid mist contributes to condensable PM₁₀/PM_{2.5}. This contribution should be -- but was not-- included in the modeled PM₁₀/PM_{2.5} emissions, and the Part 70 permit should include a specific requirement as to the maximum allowable SO₂ to SO₃ conversion rate of the SCR catalyst that would be used, and monitoring conditions to assure this maximum conversion rate is not exceeded.

LDEQ Response to Comment No. VII.65

The applicant must demonstrate and certify compliance with the 90% reduction requirement for NO_x from the package boilers. The source is subject to the monitoring, recordkeeping and reporting requirements of 40 CFR 60 subpart Db, which include these requirements for NO_x.

A portion of this comment is substantially the same as a portion of Comment Nos. 38 and 39. Please see LDEQ Response to Comment Nos. 38 and 39 for additional responses to this comment.

Comment No. VII.66

Permit No. 3086-VO violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for SO₂ emissions from the package boilers (DRI-109/DRI-209). The Preliminary Determination Summary concludes that BACT for SO₂ emissions from the package boilers is the use of "pipeline- quality natural gas." Specific Condition #6 limits the sulfur in the natural gas to 2,000 grains of sulfur per million standard cubic feet of gas ("gr/MMscf"). However, this BACT determination is unenforceable as incorporated into the Part 70 permit and inconsistent with the emission calculations.

First, the DRI Part 70 permit does not restrict the package boilers to burning only natural gas and it does not include the PSD Permit limit on natural gas sulfur content.

Second, neither the PSD permit nor the Part 70 permit includes any monitoring for sulfur content of the natural gas. The Part 70 permit requires only recordkeeping for the amount of each type of fuel that is burned, leaving the door open for other fuels. This allows the facility to demonstrate that it is complying with the unstated requirement to use only natural gas, but not that it is complying with the SO₂ emission limits in its permits in pounds per hour and tons per year: Sulfur content of natural gas varies widely, depending upon the field it comes from and any preconditioning that occurs.

Third, the emission rates reported in the "Emission Rate for Criteria Pollutants" table of the Part 70 permit are based on a natural gas sulfur content of 87 gr/MMscf, 23 times lower than the BACT limit specified by LDEQ. We are not aware of natural gas that has such low sulfur levels, unless specially treated with very expensive sulfur removal methods, which are not proposed here. The lower limit of sulfur in pipeline quality natural gas is typically 2,000 gr/MMscf, the level specified by LDEQ as BACT. Thus, the SO₂ emissions that were modeled from the package boilers are not achievable in practice and are 23 times lower than they will be in practice. This is problematic as the draft permits do not require any monitoring of either sulfur in the natural gas or SO₂ in the exhaust gases from the package boilers. The permits should be revised to include such monitoring.

LDEQ Response to Comment No. VII.66

BACT for emissions of SO₂ from the package boilers has been determined as combustion of pipeline quality natural gas containing 2,000 ppm or less of sulfur.

The commenter is in error in regard to the typical sulfur content of natural gas. The 2,000 gr/MMscf or less requirement is not the "lower limit of sulfur" content, and in fact would be considered exceptionally high, the upper limit, for normal delivery. This is consistent with EPA interpretations of the definition of pipeline quality natural gas. The applicant's use of 87 gr/MMscf is itself higher than would be expected on average, yet within the range of normal quality. Continuous monitoring of natural gas sulfur content is not warranted in this case, since emissions of SO₂ are predicted to be very low, as would be expected when combusting natural gas. It is incumbent upon the operator to calculate actual emissions and demonstrate compliance with the SO₂ emission rate limits of the permit. A basis for these calculations would be a natural gas analysis as provided by the supplier, direct sampling and analysis, or other technically sound method.

Comment No. VII.67

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for NO_x emissions from the reformers (DRI-108/DRI-208). The emission calculations for this source indicate that emissions from the Reformer were calculated from an emission factor expressed in lb/MMBtu and the Reformer firing rate, multiplied by the fraction (97.3%) of the total Reformer volumetric vent rate that is emitted at the Reformer stack. The balance is Reformer flue gas that is diverted ahead of the SCR and sent to the seal gas system, where it is used and vented elsewhere (DRI-106/206, DRI-112/212, DRI-107/207). This adjustment is applied to the emission rates in lb/hr and ton/yr, not the emission concentration in lb/MMBtu. The use of this factor should be explained in the Specific Requirements and the fraction required as an enforceable condition.

The PSD Permit establishes a NO_x BACT limit of 0.0070 lb/MMBtu, but the BACT emissions limitation identified in the Part 70 permit is 0.070 lb/MMBtu. Which is it? The emission limits in the Part 70 permit "Emission Rates for Criteria Pollutants" table and the emission rates modeled in the air quality analysis both are based on the lower limit, the 0.0070 lb/MMBtu. This lower limit assumes 90% NO_x removal from an uncontrolled baseline of 0.07 lb/MMBtu. This lower limit was converted to 10.36 lb/hr average and 10.88 lb/hr maximum and included in the air quality modeling. We support the use of low NO_x fuel, SCR, and low NO_x burners to control NO_x from the Reformer/Main Flue Gas Stack. However, there are several problems with the translation of these controls into BACT emission limits.

Second, the compliance monitoring requirements are ambiguous. Specific Requirement #72 requires continuous monitoring of NO_x using a CEMS. However, Specific Requirements #74, #75, and #78 indicate compliance with the emission limits would be demonstrated using only two stack tests over the life of the facility. While the credible evidence rule would allow the use of CEMS data in enforcement actions, these data would not be publicly available, preventing citizen enforcement. Further, the CEMS data would not necessarily be used to demonstrate compliance with the emission limits, absent a specific requirement. Thus, the Part 70 permit should be revised to clarify that the NO_x CEMS must be used to determine compliance with all NO_x limits and modified to require reporting of CEMS data.

Third, emission limits must be accompanied by an averaging time to assure that they are practically enforceable and to assure compliance with ambient air quality standards. No averaging times are specified for the PSD permit limit of 0.0070 lb/MMBtu or the emission rates in the Part 70 permit "Emission Rates for Criteria Pollutants" table. The compliance provision is stated as a "three one-hour test average." This means three one-hour measurements will be made, averaged together, and the average compared to the emission limit. Thus, this is a 3-hour average. A 3-hour average can mask shorter-term, 1-hour emission spikes, obscuring violations. The averaging time must be consistent with any applicable NAAQS. Thus, the permit should be modified to express the NO_x BACT emission limits as a 1-hour average confirmed by three individual 1-hour measurements.

Last, an SCR converts some of the SO₂ in the exhaust gases into sulfur trioxide ("SO₃") which exits the stack as sulfuric acid mist, a PSD pollutant that was not evaluated for PSD applicability in the DRI Application. Further, the resulting sulfuric acid mist contributes to condensable PM₁₀/PM_{2.5}. This contribution should be -- but was not-- included in the modeled PM₁₀/PM_{2.5} emissions, and the Part 70 permit should include a specific requirement as to the maximum allowable SO₂ to SO₃ conversion rate of the SCR catalyst that would be used, and monitoring conditions to assure this maximum conversion rate is not exceeded.

LDEQ Response to Comment No. VII.67

The fraction of seal gas diverted to the upper and lower seals, and the product silos, were presented to the department as integral to the design of the facility, and represent maximum rates of use. Thus, the fraction cited by the commenter represents an upper limit to the amount of seal gas used at these sources. LDEQ considers an enforceable condition requiring a specific fraction of seal gas to be diverted to the furnace seals and the silos is not in the interests of good environmental stewardship, since it would restrict the operator from directing this gas through the main stack and SCR control for NO_x at times when the full volume of gas was not needed.

The commenter correctly identifies an error in Specific Condition Nos. 80 and 239, where the BACT limitation is expressed as 0.070 lbs/MMBtu. The correct limitation of 0.007 lbs/MMBtu has replaced the error in these conditions.

The commenter incorrectly states that using the average of three one-hour tests equates to a three-hour average. Most stack testing requirements for permits are conducted on the basis of three one-hour tests, in order to mitigate the inherent variability such tests may exhibit. This provides a statistically sound basis for establishing the true emission rate. These tests form the compliance basis for the one-hour average emission limitation.

As the largest sources of NO_x at the DRI facility, and the source most likely to see variations in NO_x formation due to the combustion of spent reducing gas fuel, the reformers are required to install continuous emissions monitoring systems (CEMS). This monitoring determines compliance with the emission rate limit for NO_x. However, compliance with the emissions rate limit does not determine compliance with the BACT limit of 90% control. A performance test of the reformer unit is required, in order to determine uncontrolled NO_x emissions. By verifying the NO_x generation rate of the reformer through performance testing, reasonable assurance of compliance with the 90% control BACT limit may be maintained by the CEMS.

See LDEQ Response to Comment Nos. 38 and 39.

Comment No. VII.68

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for SO₂ emissions from the reformers (DRI-108/DRI-208). The DRI PSD permit establishes BACT limits of 0.002 lb SO₂/MMBtu and use of natural gas containing no more than 2,000 gr/MMscf for both DRI-108 and DRI-109. Neither of these limits is carried over into the DRI Part 70 permit. These are applicable requirements that must be included in the Part 70 permit. Instead, the Part 70 permit limits natural gas use to ≤13 MMBtu per metric ton ("MMBtu/tonne") of direct reduced iron.

Second, the Part 70 permit sets a limit on the amount of natural gas expressed as ≤13 MMBtu/tonne. This is presumably a surrogate for SO₂ as the Part 70 permit does not otherwise specify a SO₂ BACT limit. This limit on natural gas is not consistent with the underlying emission calculations. These calculations indicate that one reformer will produce 2,500,000 tonne/yr or 312.5 tonne/hr of DRI. The normal reformer firing rate is 1,521 MMBtu/hr, of which 38.24% is natural gas. This works out to 1.86 MMBtu of natural gas per tonne DRI. The basis for the BACT limit of ≤13 MMBtu/tonne is not evident. Could this be a limit on the amount of top gas?

Third, the compliance provisions for the BACT limit of ≤13 MMBtu/tonne are found in Specific Requirement #82 for DRI-108, which requires tracking of DRI production and natural gas consumption. This condition is ambiguous as it refers to Subparts C and Q, without identifying the underlying part of the CFR and it does not specify the method that will be used to determine DRI production and natural gas consumption. Further, this condition is missing from the Specific Requirements for DRI-208, which includes the same limit of ≤13 MMBtu/tonne.

LDEQ Response to Comment No. VII. 68

The comments in regard to natural gas sulfur content are substantially the same as Comment Nos. 17, 33 and 67. Please see LDEQ Response to Comment Nos. 17, 33, and 67 for our position

regarding this portion of Comment No. VII. 68.

The limit of 13 MMBtu/tonne of DRI production is BACT for emissions of GHG. This limit is unrelated to the BACT determination for emissions of SO₂. Because this limit is applied to the facility as a whole, inclusive of all combustion sources and natural gas consumption as a raw material, this specific requirement has been moved to the facility-wide requirements for clarity. LDEQ agrees that the monitoring provisions for compliance with this requirement should also be made clearer, and have included these monitoring requirements under facility-wide specific conditions as well.

Comment No. VII.69

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for CO emissions from the reformers (DRI-108/DRI-208). The DRI PSD Permit specifies good combustion practices as BACT for both CO and VOC. However, the DRI Part 70 permit does not require good combustion practices for either CO or VOC. These are applicable requirements which must be included in the Part 70 permit.

Second, the PSD Specific Conditions establish an emission limit of 0.039 lb/MMBtu as BACT for CO, but the Part 70 permit identifies CO BACT as " ≤ 0.040 lb/MMBtu as adjusted for seal gas system off-take portion from total Reformer flue gas generated by combustion fuel gases. It is unclear whether these two limits are equivalent. The apparent discrepancy between these two limits should be resolved. Further, the phrase "adjusted for seal gas system off-take portion from total Reformer flue gas generated by combustion fuel gas" is unclear and should be defined in the permit and the specific calculation required laid out.

Third, the Specific Requirements do not incorporate any BACT emission limits or other restrictions on operations designated as BACT to control VOC emissions.

LDEQ Response to Comment No. VII.69

The positions taken by the commenter with respect to good combustion practices are substantially the same as those in Comment No. VII.15. Please see LDEQ Response to Comment No. VII.15 for our response to this position.

The commenter's assertion that the BACT limit for CO from the reformers is listed in the PSD permit as 0.039 lb/MMBtu is factually incorrect. The maximum allowable emission rate limit is listed as 0.040 lb/MMBtu for the reformers.

Comment No. VII.70

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate any applicable PSD requirements for the upper sealgas vents (DRI- 106/DRI-206). The DRI PSD permit establishes BACT emission limitations, in the form of ton-per-year emission rates, for PM₁₀, PM_{2.5}, NO_x, SO₂, and CO emissions from the Upper Seal Gas Vent (DRI-106/-206). These BACT emission limits, which are applicable requirements, were not transferred to the DRI Part 70 permit. In fact, the upper Seal Gas Vents are omitted as emission points from the Specific Requirements. These sources were modeled and are listed elsewhere, including in the Emission Rates for Criteria Pollutants table, in the Inventories table, and in the Emission Inventory Questionnaire sheets, but are omitted from the Specific Requirements. The Specific Requirements must

incorporate all applicable PSD requirements for these two sources and must include monitoring and recordkeeping as necessary to assure continuous emission reductions and compliance with BACT.

LDEQ Response to Comment No. VII.70

As discussed in LDEQ Response to Comment No. VII.24, BACT for the upper seal gas vent is more properly addressed in the Title V permit as specific requirements at the reformers. In that regard, this comment is substantially the same as Comment Nos. 24, 25, 26, and 27. See LDEQ Response to Comment No. VII.24 for our response to this comment.

Comment No. VII.71

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for furnace dedusting (DRI- 107/DRI-207). The DRI Part 70- permit does not require that Nucor install the BACT control technology, but rather, only places limits on its operation in the form of a concentration and emission rates in lb/hr and ton/yr which are measured only once over the lifetime of the facility and an unspecified scrubber flow rate (2: 0.00 gal/min). The Part 70 permit should be modified to include a specific requirement that requires the installation of a 99% efficient scrubber.

Second, Specific Requirements #61 and #219 allows setting a scrubber flow rate or pressure differential limit/range after the facility is built, under an administrative permit amendment. The Part 70 permit does not disclose the purpose of this operational limit, but presumably, it is being used as a surrogate for PM₁₀ under the theory that the PM₁₀ emission limits would be met if the scrubber were operating properly. However, this has not been established in the permit record. Further, Specific Requirements #61 and #219 do not require any demonstration of a relationship between PM₁₀ and the chosen operational parameters. No public review is required for an administrative amendment. As the scrubber flow rate/differential pressure are used to assure compliance with applicable requirements in a Title V permit and a PSD permit which are individually subject to public review, these limitations are likewise subject to public review. Further, the Part 70 permit should explain the purpose of this limit and establish the resulting scrubber flow or pressure differential limits/ranges as enforceable conditions.

Last, the permit requires only a single stack test over the life of the facility to determine compliance with the PM₁₀ emission limit of 0.002 gr/dscf and the emission rates in lb/hr and ton/yr in the Emission Rates for Criteria Pollutants table. Compliance can only be determined if a stack test is conducted to directly measure the concentration of PM₁₀/PM_{2.5} in the exhaust gases and the exhaust gas flow rate. The permit only requires routine measurement and reporting of the scrubber flow rate. This reveals no information about PM₁₀ concentrations expressed in gr/dscf or PM₁₀ emission rates expressed in lb/hr and ton/yr, unless studies are conducted to establish a statistically valid relationship between flow rate and these emission metrics. Any such relationship would only be valid for the conditions under which it was developed. If the iron ore composition changed or process operating conditions change, any such relationship would change. Thus, the proffered BACT limits are not enforceable as a practical matter. The permit should be revised to require at least annual stack testing to measure particulate emission limitations expressed as gr/dscf, lb/hr and ton/yr coupled with valid indicator monitoring.

LDEQ Response to Comment No. VII.71

LDEQ incorporates all requirements of Permit PSD-LA-751 to Part 70 Permit No. 3086-V0 by reference in Specific Requirement 294.

The BACT determination establishes the control technology (scrubber), the emission limit and the **method** by which compliance will be determined (a stack test that will establish parametric monitoring, namely the pressure drop). The exact range for the parametric monitoring can not be established preconstruction. (It is dependant upon the facility actually constructed.) This satisfies the requirements for a PSD permit.

LDEQ has required performance tests of sources subject to a technology-based BACT determination, such as a high-energy scrubber. These tests are then supported by adequate parametric monitoring to assure compliance with the permitted limits, using parameter ranges determined to demonstrate compliance by the test, such as pressure drop or scrubber liquid flow rate. The use of parametric monitoring techniques is commonplace in environmental permits issued in Louisiana, and throughout the United States. Performance testing must be conducted at the process conditions which would be expected to generate the maximum emissions, which is not necessarily at the highest processing capacity for any given source. The commenter speculates that the results of such test would become invalid "if the iron ore composition changed or process operating conditions change," but fails to support the contention that such changes would invalidate performance test results required to be obtained under worst-case operating conditions.

Comment No. VII.72

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for screening and transport (DRI- 115/DRI-215). The DRI Part 70 permit includes two types of applicable requirements for sources DRI-115/116: (1) a PM₁₀ concentration in gr/dscf (Specific Requirements #132, #137); and (2) PM₁₀ emission rates in lb/hr and tons/yr in the Emission Rates for Criteria Pollutants table. Compliance is determined by indicator monitoring without any direct testing. This scheme does not ensure compliance with these applicable requirements.

First, the permit does not require any testing or recordkeeping to determine compliance with the PM₁₀ emission limits (≤ 0.002 gr/dscf) nor any of the emission rates in lb/hr and ton/yr that were calculated from it. Compliance can only be determined if a stack test is conducted to directly measure the concentration of PM₁₀/PM_{2.5} in the exhaust gases and the exhaust gas flow rate. The draft permits require measurement of scrubber flow rate but this reveals no information about particulate concentrations expressed in gr/dscf or emission rates expressed in lb/hr and ton/yr, unless studies are conducted to establish a relationship between flow rate and these emission metrics. As noted above, many Title V permits have been remanded for similar failures.

Second, the permit requires determining target flow rates or pressure drop required to satisfy "the PSD limitation," presumably the BACT limit, but does not identify the limitation (Specific Requirement #147). One must guess that it is PM₁₀ and speculate whether it covers just the gr/dscf limit or also includes the lb/hr and ton/yr limits.

Third, this determination would occur after the facility is constructed and operating. This post-construction determination does not satisfy BACT, which is a preconstruction requirement. As the draft permits do not allow for review of the resulting thresholds by the public, this condition violates the public participation requirements of both PSD and Title V.

Fourth, the permit does not disclose the purpose of this indicator monitoring, but presumably, it is being used as a surrogate for PM₁₀ under the assumption that if

emissions are directed to a scrubber and the scrubber is functioning properly, the scrubber will achieve 0.002 gr/dscf and meet the lb/hr and ton/yr emission limitations. However, this has not been demonstrated, and absent a demonstration, no direct testing is not adequate to demonstrate continuous compliance. Therefore, the Specific Requirements should require a demonstration that this assumption is valid and further state that exceedances of the indicators are a violation of the underlying BACT emission limit.

LDEQ Response to Comment No. VII.72

The commenter is correct that explicit requirements to conduct a performance test were not included for these sources. Such requirements would be consistent with testing requirements for other wet scrubber control devices at the facility. Testing requirements consistent with other wet scrubber control devices at the facility have been added to sources DRI-115, DRI-215, DRI-116, and DRI-216.

See LDEQ Response to Comment No. VII.71 for our response to the compliance assurance aspects of Comment No. VII.72.

Comment No. VII.73

Permit No. 3086-V0 violates Title V of the Clean Air Act because the permit does not incorporate all applicable PSD requirements for product storage silos (DRI-112/DRI-212). The DRI Part 70 permit includes a single stack test (Specific Requirement #111, #267) coupled with indicator monitoring (Specific Requirements #110, #266) to determine compliance with the BACT PM₁₀ emission limitations.

The permit allows setting a scrubber flow rate or pressure drop range to assure compliance with the PSD limitation but fails to identify which limitation is the target (Specific Requirements #110, #266). One must guess that it is PM₁₀ and speculate as to whether it covers just gr/dscf or also the lb/hr and ton/yr limits. The flow rate and pressure drop allowable ranges would be determined after the facility is built, under an administrative permit amendment. No public review is required for an administrative amendment. As the scrubber flow rate/pressure drop is likely a surrogate to determine continuous compliance with a BACT emission limit, it must be subject to public review. These post-construction studies do not satisfy BACT, which is a preconstruction requirement and thus violate the public participation requirements of both PSD and Title V.

Second, the permit does not disclose the purpose of this flow rate/pressure drop monitoring, but presumably, it is being used as a surrogate for PM₁₀ under the assumption that if emissions are directed to a scrubber and the scrubber is functioning properly, the scrubber will achieve 99% PM₁₀ removal and meet the gr/dscf and lb/hr emission limitations. Therefore, the Specific Requirements should state that exceedances of these future thresholds would be a violation of the underlying BACT emission limit.

Third, the permit requires only a single stack test over the life of the facility to determine compliance with the PM₁₀ emission limit of 0.002 gr/dscf and the emission rates in lb/hr and ton/yr in the Emission Rates for Criteria Pollutants table. The permit must include sufficient monitoring to assure continuous compliance. Compliance can only be determined if a stack test is conducted to directly measure the concentration of PM₁₀/PM_{2.5} in the exhaust gases coupled with the exhaust gas flow rate. The permit only requires routine measurement and reporting of the scrubber flow rate (Specific Requirement #112, #268). While a limitation may be placed on pressure drop, no

monitoring or reporting is required in the Part 70 permit.

Flow monitoring reveals no information about PM₁₀ concentrations expressed in gr/dscf nor lb/MMBtu or PM₁₀ emission rates expressed in lb/hr and ton/yr, unless studies are conducted to establish a statistically valid relationship between flow rate and these emission metrics. Thus, Specific Requirements #110 and #266 should require a study to demonstrate a relationship between the flow/pressure and the subject applicable requirements. Otherwise, the proffered BACT PM₁₀ limit is not enforceable as a practical matter and the Part 70 permit does not assure compliance with the applicable requirements.

Any such relationship would only be valid for the conditions under which it was developed. If the iron ore composition changed or process operating conditions changed, any such relationship would change. The permits should be revised to require at least annual stack testing to measure particulate emission limitations expressed as gr/dscf, lb/MMBtu, lb/hr and ton/yr to test the validity of the relationship and to directly determine compliance. The study to establish the indicator relationship should be repeated every 5 years or whenever a change occurs that would affect scrubber emissions. The permit record should -- but does not -- explain anywhere how a single stack test over the life of the facility (Specific Requirement # 111, #267), the only method of measuring the actual PM₁₀ emissions, and scrubber flow/pressure monitoring every four hours (Specific Requirements #113, # 268) are sufficient to assure the scrubber is continuously achieving 99% PM₁₀ control and meeting PM₁₀ emission rates used in the source impact analyses.

LDEQ Response to Comment No. VII.73

This comment is substantially the same as Comment No. VII.71. Please see LDEQ Response to Comment No. VII.71 for our response to this comment.

Comment No. VII.74

The applicable PSD requirements for paved road fugitive dust (FUG-102) incorporated in Permit No. 3086-V0 are not practicably enforceable. Regardless of the reason for transferring this source from the initial pig iron Part 70 permit to the DRI Part 70 permit, the DRI Part 70 permit must include sufficient monitoring to assure continuous compliance with all applicable requirements. As noted in comments above, the complete BACT determination for paved and unpaved roads was not transferred to the DRI Part 70 permit. That omission should be corrected. Nonetheless, the DRI Part 70 permit must assure continuous compliance with those portions of BACT that were transferred, including Specific Requirement #2 ("roadway watering, periodic sweeping and reduced speed limit of less than or equal to 15 mph on paved road"), and also with the emission rates in the Criteria Pollutant Emission Rate table. The only enforcement provision is to take "all reasonable precautions" to prevent particulate matter from becoming airborne, where such precautions include those specified in LAC 33:III.1305.A.1-7 and the NSLA Dust Management Plan (Specific Requirement #1). This requirement is ambiguous because "all reasonable precautions" is not defined. Do LAC 33:III.1305.A.1-7 and the Dust Control Plan constitute "all reasonable precautions" or is something more required? LDEQ must remove the term "all reasonable precautions" from this condition, define the term, or provide criteria to determine "all reasonable precautions."

Second, the permit record does not explain anywhere how any of these control options are sufficient to assure compliance with the emission rates included in the source impact

analysis.

Third, the DRI Part 70 permit does not require any recordkeeping or reporting for FUG-102. At a minimum, the Permit should be revised to test for, record, and report all of the operating and other assumptions used in the underlying emission calculations, including road surface silt content, vehicle miles traveled, number and type of trucks, amount and type of dust suppressant used, etc.

LDEQ Response to Comment No. VII.74

To mitigate emissions from the Paved Road Fugitive Dust (FUG-102) Nucor must water roadways, conduct periodic sweeping, and reduce the speed limit of vehicle traffic of 15 mph or less, per Specific Condition #2, and take all reasonable precautions to prevent particulate matter from becoming airborne due to any other reason. These precautions shall include, but not be limited to the most currently-approved Nucor Steel Louisiana Dust Management Plan. Compliance with the Dust Management Plan is a requirement of both the Title V and PSD permits. Direct measurement of emissions from paved roads is not technically feasible. According to the definition of —Best Available Control Technology (BACT),"if —the administrative authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology." The Dust Management Plan meets the work practice standard threshold of assuring compliance with BACT.

Comment No. VII.75

The applicable PSD requirements for the loading/unloading gantry crane (DOC-101) incorporated in Permit No. 3086-V0 are not practicably enforceable. The DRI Part 70 permit contains three applicable requirements for this transferred source: Specific Requirements #4 (total suspended particulate \leq 89.80 lb/hr); Specific Requirement #6 (control technologies and work practice standards to satisfy BACT for conveyors and loading/drop points); and the PM₁₀ emission rates in the Emission Rates for Criteria Pollutants table. The only compliance provision is an annual measurement of the moisture content of each product loaded or unloaded (Specific Requirement #5). This is not adequate to assure compliance with these applicable requirements.

First, moisture content is only one of the variables used to calculate PM₁₀/PM_{2.5} emissions from loading and unloading, as discussed above. This variable standing alone is not adequate to assure compliance with the applicable requirements as the emission rate calculation requires throughput, number of drops, and control efficiency, among others. The DRI Part 70 permit should be modified to require measurement, recordkeeping, and reporting of these additional variables, coupled with a calculation to demonstrate compliance with emission rates in lb/hr and ton/yr.

Second, the DRI Part 70 permit does not specify any method for measuring the moisture content. Section 504(c) of the CAA requires all Title V permits to contain monitoring requirements to assure compliance with permit terms and conditions. The test method is part and parcel of monitoring and must be specified to assure compliance. See *In the Matter of Wheelabrator Baltimore, L.P., Baltimore, Maryland, Order Partially Granting and Partially Denying the Petition for Objection to the Permit*, April 14, 2010, pp. 9-10 ("EPA agrees that MDE does not have the discretion to issue a permit without specifying the monitoring methodology needed to assure compliance with applicable requirements in the Title V permit."); U.S. EPA Region 4 Objection, Proposed Part 70 Operating

Permit, Southdown, Inc - Brooksville Plant, Hernando County, Florida, Permit No. 0530010-002-AV, June 19, 2000, Objection 6 ("Because these numerical values are view as specific permit limits, the permit must address how the moisture content of these materials will be monitored or maintained above specified moisture levels to ensure compliance with this conditions."); and In the Matter of Luke Paper Company, Subsidiary of New Page Corporation, Order Partially Granting and Partially Denying the Petition for Objection to the Permit, October 18, 2010, p. 5 ("EPA agrees that MDE does not have the discretion to issue a permit without specifying the monitoring methodology needed to assure compliance with applicable requirements in the Title V permit.").

Third, the permit record does not explain anywhere how an annual measurement of moisture content is sufficient to assure compliance with applicable requirements. An annual measurement is not adequate to assure compliance with 24-hour PM₁₀ and PM_{2.5} air quality standards. Similarly, an annual testing frequency, for example, is far too long to capture the variability that could be introduced by changes in material composition or ambient conditions. Is the moisture content on a hot summer day the same as on a winter day? The moisture content should be measured at least weekly as the loading/unloading emissions are very sensitive to variations in this parameter, as explained above.

LDEQ Response to Comment No. VII.75

LDEQ has determined direct measurement of emissions is not technically feasible. The Title V permit requires Nucor to analyze the moisture content of each product loaded or unloaded at the dock annually and to compare the sample moisture content values to those used in the most current application emission calculations, except that shipping records with documented moisture content can be substituted for the annual samples and analysis. Such a requirement is a "monitoring methodology", and the method in which LDEQ has addressed "how the moisture content of these materials will be monitored or maintained above specified moisture levels". Therefore, LDEQ has not issued a permit without specifying the monitoring methodology for this operational parameter.

LDEQ has required an annual determination of moisture content in order to validate the assumptions used in the emissions calculations for material unloading. These analyses are then supported by the designed capacity of the conveyance system to move material from the dock hopper to the facility storage piles. As noted by the commenter elsewhere in these comments, the applicant included a 15% safety factor in the calculation of these emission rates, to provide ample room to demonstrate compliance on an as-built basis. The combination of moisture content analyses and conveyance capacity design were deemed sufficient to determine compliance with the maximum one-hour emission limitation listed in the permit; and as such the averaging time for this determination is one hour. This method of testing one-hour intervals at the maximum physical capacity of the emitting equipment assures compliance with the BACT limitations stated in the PSD and Title V permits.

Comment No. VII.76

The applicable PSD requirements for conveyor fugitives (FUG-103) incorporated in Permit No. 3086-V0 are not practicably enforceable. The DRI Part 70 permit includes contains two applicable PSD requirements for this transferred source: Specific Requirements #3 (control technologies and work practice standards to satisfy BACT for conveyors and loading/drop points) and the PM₁₀ emission rates in the Emission Rates for Criteria Pollutants table. The DRI Part 70 permit contains no compliance provision for these requirements or explanation of why none is required. The permit should be modified to include terms and conditions to assure continuous compliance with the FUG-103 applicable requirements, including monitoring, recordkeeping, and reporting.

LDEQ Response to Comment No. VII.76

To mitigate emissions from the Conveyor Fugitives (FUG-103) Nucor must utilize enclosed conveyors, water sprays, and partial enclosures, per Specific Condition # 3, and take all reasonable precautions to prevent particulate matter from becoming airborne. These precautions shall include, but not be limited to, the most currently-approved Nucor Steel Louisiana Dust Management Plan. Compliance with the Dust Management Plan is a requirement of the Title V permit.

LDEQ determined that direct measurement of emissions from conveyor fugitives is not technically feasible. According to the definition of —Best Available Control Technology (BACT),"if —the administrative authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology." Compliance with the emission rate limitation must be demonstrated on the basis of operating the conveyors in a manner consistent with the design basis presented in the calculations, and the approved Nucor Steel Louisiana Dust Management Plan.

Comment No. VII.77

The applicable PSD requirements for the iron ore storage piles (PIL-102) incorporated in Permit No. 3086- VO are not practicably enforceable. The DRI Part 70 permit includes contains several applicable requirements for this transferred source, including PM_{2.5} emission rates in lb/hr and ton/yr (Specific Requirements #284-286) and PM₁₀ emission rates in the Emission Rates for Criteria Pollutants table. The permit contains neither compliance provisions for these requirements nor any explanation of why none is required. The permit should be modified to include terms and conditions to assure continuous compliance with the PIL-102 applicable requirements, including monitoring, recordkeeping, and reporting.

LDEQ Response to Comment No. VII.77

This comment is substantially the same as Comment No. VII.76. Please see LDEQ Response to Comment No. VII.76 for our response to this comment.

Comment No. VII.78

The CAM Plan does not comply with the requirements of 40 C.F.R. Part 64. The Compliance Assurance Monitoring Plan ("CAM Plan") for the DRI facility was submitted to LDEQ on October 22, 2010 as Attachment 3 to the Second Addendum to the DRI Application pursuant to 40 CFR 64.186 There are two fundamental problems with the CAM Plan and its interaction with the Part 70 permits: (1) the CAM Plan itself is defective and (2) the Part 70 permits fail to properly incorporate CAM Plan requirements. Compliance assurance monitoring requires the collection of sufficient data to reasonably assure compliance with subject emission limitations or standards. This data must include one or more indicators of emission control performance, an appropriate range for the indicator(s), and performance criteria. 40 C.F.R. § 64.3. The CAM Plan does not address the BACT emission limitations, excludes most of the subject sources at the DRI Plant, omits subject sources that emit NO_x and SO₂, and fails to include adequate monitoring. Each of these issues is addressed below.

A CAM Plan should provide a reasonable assurance of compliance with subject emission

limitations or standards for the anticipated range of operations. 40 C.F.R. § 64.3. As discussed elsewhere, compliance assurance monitoring is required for PM₁₀, NO_x, and SO₂ for subject sources. Thus, the Plan must provide a reasonable assurance of compliance with the BACT limitations and other limitations and standards for these pollutants. However, the CAM Plan is silent as to BACT and other limitations, instead setting a 20% opacity limit and tons-per-year limits from the Emission Rates for Criteria Pollutants table. However, neither of these (opacity, ton/yr PM₁₀) is an emission limitation or standard for purposes of CAM compliance, but presumably indicators for the BACT PM₁₀ concentration limit, among others. The CAM Plan never identifies the limitations and standards it is seeking to assure compliance with.

The CAM Plan should have proposed monitoring to assure compliance with the BACT emission limitations. The permit record contains no evidence that the monitoring in the CAM Plan (or anywhere else) would assure compliance with any of the subject BACT emission limitations. These include Specific Requirements #24 (PM₁₀ for DRI-101); #44 (PM₁₀ for DRI-102); #68, 70 (NO_x, PM₁₀ for DRI-107); #80 (NO_x for DRI-108); #117,118 (NO_x, PM₁₀ for DRI-112); #132 (PM₁₀ for DRI-115); #137 (PM₁₀ for DRI-116); #173 (PM₁₀ for DRI-201); #192 (PM₁₀ for DRI-202); #198 (PM₁₀ for DRI-205); #227,228 (NO_x, PM₁₀ for DRI-207); #237,239 (PM₁₀, NO_x for DRI-208); and #273, 275 (NO_x, PM₁₀ for DRI-212). The LDEQ failed to explain in the permit record how the CAM monitoring assures compliance with the BACT emission limits for PM₁₀, SO₂, or NO_x for units subject to CAM.

LDEQ Response to Comment No. VII.78

Sources of PM₁₀, NO_x and SO₂ have federally enforceable conditions limiting their Potential to Emit below major source status for these pollutants. As such, they do not meet the threshold of being *Large Pollutant-Specific Emissions Units* under 40 CFR 64.5(a). Therefore, the reformers are classified as *Other Pollutant-Specific Emissions Units* under 40 CFR 64.5(b), which does not require a CAM plan to be submitted as part of an initial part 70 permit. These units will be required to submit a CAM plan as part of an application for renewal of the part 70 permit, pursuant to 40 CFR 64.5(b).

Since the DRI facility does not have sources which require the submittal of a CAM plan with the initial part 70 permit application, and a CAM plan for these sources was not submitted; the commenter's assertion that the CAM plan is defective or insufficient is without merit. The commenter correctly identified that CAM requirements were included for sources DRI-101, DRI-102, DRI-201, and DRI-202. These requirements were inadvertently selected, and have been removed from the permit for consistency with the CAM applicability analysis described above. The monitoring requirements, however, have been retained, and will be cited as LAC 33:III.507.H.1.a.

Comment No. VII.79

The CAM Plan should -- but does not -- include NO_x emissions from the reformers. The CAM Plan contains a section on NO_x but does not list any of the subject NO_x- emitting DRI source. The Reformers (DRI-108/208) are subject to CAM because they have a NO_x BACT emission limitation that does not meet the exemption criteria; they use a control device to achieve compliance (SCR); they emit pre-control potential to emit major source amounts; and they are not otherwise exempt from CAM. Thus, CAM should apply, and the Reformers should be included in the CAM Plan and CAM monitoring required in the Title V Permit. However, paradoxically, the Specific Requirements list the CAM regulations as applicable to DRI-109/209, the Package Boilers. See Specific Requirements #85-93 for DRI-109 and #241-249 for DRI-209. Thus, we wonder if

LDEQ inadvertently listed these CAM requirements for the wrong source? [Original document included footnote 187, which states “The SCR proposed to control NOx emissions from the Reformers will use a 90% efficient SCR. Thus, the uncontrolled emissions would be: $41.45 / 0.10 = 414.5$ ton/yr.”]

LDEQ Response to Comment No. VII.79

The commenter is in error, Specific Requirement Nos. 85 – 93 and 241 – 249 list requirements applicable to the source under NSPS subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The reformers are not subject to this NSPS subpart because they are not steam generating units.

As the commenter identifies in footnote 187, the reformers do not have post-control emissions greater than 100 tons per year. As such, they do not meet the threshold of being *Large Pollutant-Specific Emissions Units* under 40 CFR 64.5(a). Therefore, the reformers are classified as *Other Pollutant-Specific Emissions Units* under 40 CFR 64.5(b), which does not require a CAM plan to be submitted as part of an initial part 70 permit. These units will be required to submit a CAM plan as part of an application for renewal of the part 70 permit, pursuant to 40 CFR 64.5(b).

Comment No. VII.80

The CAM Plan should -- but does not -- include SO₂ emissions from the reformers. The CAM Plan does not contain a section on SO₂ and is silent as to why it is omitted. Uncontrolled SO₂ emissions from each Reformer exceed 230 ton/yr ($11.5/0.05=230$ ton/yr) and thus exceed the major source threshold of 100 ton/yr. Further, the SO₂ emissions from the Reformer are controlled by acid gas scrubbing designed to remove 95% of the SO₂ from the top gas before it is blended with natural gas for use as fuel in the Reformer, which was established as BACT. The acid gas scrubber must meet the 95% control efficiency and the Reformer must meet the average lb/hr, maximum lb/hr, and average ton/yr SO₂ emission limitations in the Emission Rates for Criteria Pollutants table, established assuming 95% removal of sulfur from the top gas. These were established pursuant to BACT. Further, the PSD source impact analyses required under LAC 33:III.509.K modeled the maximum hourly SO₂ emission rates. Thus, the Reformer is subject to an SO₂ emission limitation and thus is subject to CAM.

LDEQ Response to Comment No. VII.80

This comment is substantially the same as Comment No. VII.78. Please see LDEQ Response to Comment No. VII.78 for our response to this comment.

Comment No. VII.81

The CAM Plan should -- but does not -- address the DRI process. The CAM Plan appears to have been written for the pig iron process and modified as an afterthought for the DRI process. The only portion that pertains to the DRI process is a table in Section II.A that lists 12 sources in the DRI process that are subject to CAM for PM. Otherwise, only the pig iron process is discussed. This creates significant confusion and falls far short of an adequate CAM Plan for the DRI process.

For example, Section I, Background, discusses only the pig iron process. Plan at 1. The introduction to Section II, PM Emission Sources CAM Applicability Determination, discusses only the seven emission units in the pig iron process that are subject to CAM. Plan at 1-2. Section II.C discusses only the sources in the pig iron process controlled by

baghouses. Plan at 2-3. The monitoring approach in Section II.D applies to the seven sources in the pig iron process controlled by baghouses. Plan at 3.

The balance of the sections on particulate matter discusses only baghouses, while eight of the 12 DRI sources listed in the table use liquid scrubbers. See, e.g., "prior to testing, an inspection of each baghouse ... " "the baghouse flow rate will be recorded during the stack test." "In general, an increase in visible emissions indicates reduced performance of the baghouse (i.e., loose or torn bags)." "In general, baghouses are designed to operate at a relatively constant pressure drop." "Implementation of a baghouse inspection and maintenance 0 program provides assurance that the baghouse is in good repair and operating properly." Plan at 3-4. The CAM Plan does not include any monitoring provisions for these wet scrubbers. Finally, the NO_x section only addresses pig iron sources and is silent as to the DRI process. Plan at 4-6.

Thus, while the CAM Plan was attached to the DRI Application, it was clearly drafted for the pig iron process. The DRI sources were added to Table II.A as an afterthought without bothering to incorporate any monitoring for the eight DRI sources controlled by scrubbers or addresses subject DRI sources that emit NO_x and SO₂. A separate CAM Plan should be prepared for the DRI process.

LDEQ Response to Comment No. VII.81

This comment is substantially the same as Comment No. VII.78. Please see LDEQ Response to Comment No. VII.78 for our response to this comment.

Comment No. VII.82

Indicators in the CAM Plan are inadequate. CAM monitors compliance "by requiring each major source owner to design a site-specific monitoring system sufficient to provide a reasonable assurance of compliance with emission standards." Natural Resource Defense Council, Inc. v. EPA, 194.F.3d (D.C. Cir. 1999). The Title V Permit must contain sufficient monitoring to assure compliance with the terms and conditions of the permit. 40 CFR 70.69(c)(1). See also 40 CFR 70.6(a)(3)(i)(B). As explained in the preamble to the 1997 CAM rule:

The CAM approach builds on the premise that if an emissions unit is proven to be capable of achieving compliance as documented by a compliance or performance test and is therefore operated under the conditions anticipated and if the control equipment is properly operated and maintained, then there will be a reasonable assurance that the emission unit will remain in compliance ... Thus a critical issue that the CAM approach must address is establishing appropriate objective indicators of whether a source is "properly operated and maintained." 62 FR 54,909,54926 (October 22, 1997).

The DRI CAM Plan fails this fundamental requirement. The indicators selected for particulate matter are opacity and PM₁₀ emissions in ton/yr. There is no information or analysis cited or incorporated into the permit record that demonstrates compliance with these indicators means the baghouse will operate properly and be able to meet the BACT PM₁₀ emission limitations. In fact, there is much to suggest the opposite.

First, opacity will be monitored once a day using EPA Method 9. Plan at 3. This is not adequate to assure the baghouse will meet the opacity standard at any other time. Opacity is commonly monitored continuously by a Continuous Opacity Monitoring System or COMS coupled with a short-term averaging period on the order of minutes. The method

proposed by Nucor would allow the baghouse to be out of compliance with the opacity indicator up to 86% of the time without being detected. We recommend that a COMS be used to monitor opacity, coupled with a very short averaging time.

Second, the PM₁₀ emission rate is specified in ton/yr. Plan at 2. This indicator is measured only once a year in an annual stack test based on three test runs each lasting 4 hours. Plan at 3. In the first year of operation, compliance cannot be determined until the end of the year, leaving an entire year with no compliance determination. A ton/yr indicator based on only 12 hours of data reveals nothing about the operation of the baghouse or compliance with the BACT limit at any other time, or 99.9% of the time. Thus, the ton/yr limits should be replaced by a maximum lb/hr limit, measured every 15-minute using a PM CEMS and averaged hourly to determine compliance.

Third, the stack testing, conducted during start-up and once every 12 months using EPA Method 5 uses the wrong method. The applicable requirement is a PM₁₀ concentration limit. Thus, Method 202 should be specified. Further, prior to testing, the CAM Plan requires inspection of the baghouse to assure it is in good working order and presumably repair before testing. Plan at 3. This defeats the purpose of monitoring to assure compliance as it allows the operator to only perform maintenance prior to the test, assuring compliance while allowing violations at other times. The Plan should be modified to prohibit maintenance prior to a test and require the annual test to be conducted without prior warning to capture the true status of the control device.

Fourth, the Plan indicates that pressure drop will be measured at the inlet and outlet of the baghouse using a differential pressure gauge. Plan at 4. As we explain elsewhere in these comments, it is well known that pressure-drop information cannot be interpreted properly unless the flow rate is known, which is not monitored under the CAM Plan. *See McKenna et al. 2008, pp. 129-130.* Inlet-to-outlet pressure drop across baghouses cannot detect leaks in individual bags or even several individual bags. This requires the use of a much more effective bag leak detection system. These are commonly specified for baghouse monitoring in PSD permits. *See, e.g. PSD Permit for WE Energies Elm Road Generating Station; Permit No. 06100067-01, issued to Minnesota Steel Industries.* Further, the specific differential pressure range of 3.5 to 11 inches of water is excessively broad as baghouses typically operate at a constant pressure. Plan at 4. Thus, this range will not assure compliance and must be narrowed based on actual testing.

Finally, there is no information or analysis cited or incorporated into the Permit that demonstrates compliance with the opacity and ton/yr indicators automatically means compliance with the PM₁₀ BACT limit. The LDEQ must establish an accurate quantitative correlation between compliance with CAM requirements and compliance with the BACT PM₁₀ limit. There are no quantitative requirements in the permit record that ensure any level of performance of the control device. *See Petition Number VIII-2009-01, Objection 1, pp. In the Matter of Public Service Company of Colorado, dba Xcel Energy, Hayden Station 4-9.*

LDEQ Response to Comment No. VII.82

For the reasons stated in LDEQ Response to Comment No. VII.78, a CAM Plan does not exist for sources at the DRI facility. The commenter's assertion that the CAM plan is defective or insufficient is without merit.

Comment No. VII.83

The CAM Plan contains errors that should be corrected. Errors include:

- The PM₁₀ emissions from DRI-112 and 212 should be changed from 3.37 ton/yr to 3.08 ton/yr, to agree with the Emission Rates for Criteria Pollutants table
- The emission point IDs in the table listing CAM subject particulate emission units and emission rates (Plan at 2) are incorrect for DRI-201 (incorrectly listed as DRI-101), DRI-202 (incorrectly listed as DRI-12), DRI-207 (incorrectly listed as DRI-107), and DRI-212 (incorrectly listed as DRI-112).
- DRI-205 is omitted from the CAM Subject Emission Units. Plan at 2.
- The text only discusses the pig iron plant
- The Plan at 3, incorrectly states baghouses have a 99% efficiency rating

LDEQ Response to Comment No. VII.83

For the reasons stated in LDEQ Response to Comment No. VII.78, a CAM Plan does not exist for sources at the DRI facility. The commenter's assertion that the CAM plan is defective or insufficient is without merit.

Comment No. VII.84

The Part 70 permits fail to incorporate CAM Plan requirements. Under 40 C.F.R. § 64.6(c), if LDEQ approves the proposed monitoring in the CAM Plan, it must establish permit terms or conditions that specify the required monitoring in the Title V Permit. At a minimum, the Part 70 permits must include: (1) indicators to be monitored; (2) the methods used to measure the indicators; and (3) the performance requirements. 40 C.F.R. § 64.6(c)(1). Presumably, the LDEQ has approved the proposed monitoring, as the LDEQ is not following the alternate permitting approach set out in 40 C.F.R. § 64.6(e). Thus, the Specific Requirements in both permits must include the indicators and monitoring adopted in the CAM Plan to assure compliance with 40 C.F.R. Part 64. This fundamental obligation has not been met.

The CAM Plan identifies 12 DRI sources of PM₁₀ that meet the requirements for a CAM Plan: DRI-101, DRI-102, DRI-107, DRI-108, DRI-112, DRI-115, DRI-116, DRI-201, DRI-202, DRI-207, DRI-208, and DRI-112. Four of these are controlled by fabric filter baghouses (DRI-101/102, DRI-201/202) and the rest are controlled by scrubbers.

The Plan sets an opacity limit of 20% at each subject unit and adopts the PM₁₀ emission rates in ton/yr from the Criteria Pollutant Emission table as CAM emission limits. The Plan provides no basis for assuming that compliance with these indicators will reasonably assure that the applicable requirements are met. There is no evidence, for example, that meeting a 20% opacity limit and an annual emission rate in tons/yr will assure proper operation of the baghouse and thus compliance with the BACT PM₁₀/PM_{2.5} emission limits. Regardless, the 20% opacity limit is not included as a Specific Requirement for any of the CAM-subject sources in the Part 70 permits.

The CAM monitoring for the CAM-subject sources controlled by baghouses includes: (1) annual stack testing using Method 5; (2) daily visual observations using EPA Method 9; (3) continuous monitoring of baghouse differential pressure; (4) implementation of a baghouse inspection and maintenance program; and (5) corrective action. The specific requirements do not implement this monitoring, but rather summarize and cite the sections of 40 C.F.R. Part 64.

The preamble to the final CAM regulations made it clear that: "None of these

fundamental obligations under part 64 will be added as part of a part 70 permit independently of part 64. What will be added as part of the permit process are the particulars as to how a specific source owner or operator will satisfy these general part 64 requirements. The LDEQ has it exactly backward.

Some of this monitoring is already required under other regulatory programs and is included in the draft Title V Permit assuming that a "filter vent" is functionally equivalent to a "baghouse." These terms are not defined in the permit, but appear to be used interchangeably. This includes differential pressure monitoring, a differential pressure range, and recordkeeping for inspection and maintenance of the baghouse. However, most of the CAM Plan monitoring is not included in the Part 70 permits as Specific Requirements, but rather, indirectly implied as general summaries of various sections of 40 C.F.R. Part 64.

First, the Part 70 permits do not contain any CAM monitoring for sources controlled by scrubbers. The sources with no CAM monitoring at all include: DRI-107, DRI-108, DRI-112, DRI-115, DRI-116, DRI-207, DRI-208, and DRI-212. This can be ascertained by noting that the applicable regulation, 40 C.F.R. Part 64, is not cited as the source for any of the Specific Requirements. This is consistent with the CAM Plan itself, which only addresses baghouses, even though it lists the eight DRI sources controlled by scrubbers. Second, for sources controlled by fabric filter baghouses, the Part 70 permits do not include the monitoring set out in the CAM Plan, but rather vague citations to sections of 40 CFR 64 coupled with brief summaries of the general requirements, without identifying the specific conditions to implement them, e.g., annual stack tests, daily Method 9 tests, 15-minute pressure monitoring, an inspection and maintenance (I/M) plan, etc. This is true for DRI-101 (Specific Requirements #7-17); DRI-102 (Specific Requirements #26-36); DRI-201 (Specific Requirements #155-165); and DRI-202 (Specific Requirements #174-184). These all paraphrase the regulatory language of the cited section of 40 CFR 64, but fail to state the conditions from the CAM Plan that implement these regulations.

For example, Specific Requirements #12 (DRI-101), #31 (DRI-102), #160 (DRI-201), and #179 (DRI-202) require "all monitoring required under 40 CFR 64 to be collected at all times that the pollutant-specific emissions unit is operating". However, the Specific Requirements do not identify the required monitoring. "All" is not defined nor even referenced to the CAM Plan. Rather, one is left to wonder if "all" refers just to the CAM Plan monitoring, which is not specifically identified, or something else, constructed from an independent interpretation of 40 C.F.R. Part 64. Thus, all of the CAM requirements transferred to Part 70 permits as regulatory summaries, those for all of the baghouse controlled sources, are ambiguous. This includes Specific Requirements #7-17 for DRI-101; #155-165 for DRI-201; and #174-184 for DRI-202.

A search of the Permit reveals that the actual monitoring specified in the CAM Plan for baghouses is either missing entirely from the Specific Requirements or inconsistent with it. Using DRI-101 as an example, the CAM Plan requires direct measurement of the PM concentration every 12 months using EPA Method 5. The Specific Requirements do not require any direct measurement of PM concentrations for DRI-101. The CAM Plan requires that baghouse pressure drop be maintained between 3.5 and 1 inches of water, recorded in a log book as four 15-minute averages per hour. For source DRI-101, Specific Requirement #19 includes the 3.5 to 11 inches of water range for "filter vents." Is a filter vent a baghouse? However, regardless of the naming ambiguity, none of the Specific Requirements for DRI-101 establishes the CAM Plan monitoring frequency of four 15-minute averages per hour.

Similarly, the CAM Plan sets an opacity limit of 20% and establishes opacity as an indicator for good operation and maintenance of the baghouse and visual observations using EPA Method 9 once a day. Specific Requirement #23 requires a daily "visual inspection/determination" for "filter vents" but does not specify Method 9, apparently allowing an untrained observer to just take a look. Likewise, the CAM Plan requires implementation of a baghouse inspection and maintenance program. Specific Requirement #21, on the other hand, requires recordkeeping of inspection and maintenance activities, but does not require an inspection and maintenance.

LDEQ Response to Comment No. VII.84

For the reasons stated in LDEQ Response to Comment No. VII.78, a CAM Plan does not exist for sources at the DRI facility. The commenter's assertion that the CAM plan is defective or insufficient is without merit.

Comment No. VII.85

The DRI Part 70 permit must -- but does not -- incorporate all applicable requirements in the SIP for the control of emissions of sulfur dioxide. A Part 70 permit must include all applicable requirements that apply to a source, including all requirements in the SIP. 42 U.S.C. § 7661c(a). LAC 33:III Chapter 15, Emission Standards for Sulfur Dioxide, is part of the approved SIP. The provisions of this chapter apply to any single point source with the potential to emit 5 ton/yr SO₂ or more. LAC 33:III.1502.A.3. Affected sources may not discharge SO₂ in concentrations in excess of 2,000 ppmv (3-hour average) unless specifically exempted by LDEQ. LAC 33:III.1503.C. Stack testing, continuous emissions monitoring, recordkeeping and reporting are also required. LAC 33:III.1503.D, 1511 and 1513.

Each DRI reformer (DRI-108/DRI-208) will emit in excess of 5 ton/year SO₂ (specifically, 11.50 ton/year SO₂ each). Therefore, LAC 33:III Chapter 15 applies to these sources. LDEQ did not specifically exempt these sources, see EDMS Doc. 7731649, p. 21, so they are subject to the requirements of LAC 33:III.1503.C, 1511 and 1513. But, the only applicable requirement incorporated in the Part 70 permit is: "Equipment/operational data recordkeeping by electronic or hard copy once initially and annually. Record and retain at the site sufficient data to show annual potential sulfur dioxide emissions." See Specific Requirements #71 and #229. The permit cites this applicable requirement as LAC 33:III.1513.C. This is a mistake. LAC 33:III.1513.C applies only to an emission unit that is not subject to the emission limitations in Chapter 15, including the emission limitations in LAC 33:III.1503.C. See LAC 33:III.1513.C.

The Part 70 permit should be revised to incorporate the emission limitation in LAC 33:III.1503.C, the compliance testing requirements in LAC 33:III.1503.D, the continuous emission monitoring requirements in LAC 33:III.1511, and the recordkeeping and reporting requirements in LAC 33:III.1513 (except 1513.C).

Requiring these sources to comply with the emissions limitation and compliance monitoring requirements is particularly appropriate because, as illustrated by the DRI application and Preliminary Determination Summary, little is known about the operations of the reformers and top gas scrubbing systems or the emissions that will result there from, except that the operation is cyclical enough to require the installation of a hot gas flare.

LDEQ Response to Comment No. VII.85

The commenter is correct that LAC 33:III Chapter 15 applies to the reformers. LDEQ did not exempt the reformers from applicability to the rule, and does not have the discretion to do so. We determined that the single point sources in question emitted less than 250 tons per year of SO₂, and the design of these sources made an SO₂ concentration of 2,000 ppm(v) or greater in the flue gases extremely unlikely. As such, the department granted an exemption from the 2,000 ppm(v) limitation of this rule, pursuant to LAC 33:III.1503.C. A requirement to maintain credible evidence supporting the validity of the limitation exemption is required pursuant to LAC 33:III.1513.C.

Comment No. VII.86

The DRI Part 70 permit must -- but does not -- incorporate all applicable requirements in the SIP for the control of emissions of particulate matter. LAC 33:III Chapter 13, Emission Standards for Particulate Matter, is part of the approved SIP. The provisions of this chapter apply to any operation, process or activity from which particulate matter is emitted. LAC 33:III.1301.B. Chapter 13 includes the following requirements for control of fugitive emissions of dust:

All reasonable precautions shall be taken to prevent particulate matter from becoming airborne. These precautions shall include but shall not be limited to the following:

1. use of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of land;
2. application of asphalt, oil, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces which can give rise to airborne dusts;
3. installation and use of dust collectors to enclose and vent the handling of dusty materials. Adequate containment methods shall be employed during sandblasting or other similar operations;
4. open-bodied trucks transporting materials likely to give rise to airborne dust shall be covered at all times when in motion;
5. conducting agricultural practices such as tilling of land, application of fertilizers and insecticides in such a manner as to prevent dust from becoming airborne;
6. paving roadways and maintaining the roadways in a clean condition;
7. the prompt removal of earth or other material from paved streets onto which earth or other material has been transported by trucking or earth moving equipment, erosion by water or other means.

LAC 33:III.1305.A. In addition to fugitive emissions, LAC 33:III.1311 imposes opacity limits ($\leq 20\%$) and production-based mass emission limits for process sources, and LAC 33:III.1313.C imposes limitations on fuel burning equipment.

The DRI Part 70 permit and modified pig iron Part 70 permit should be revised to incorporate the following:

- For FUG-101 and FUG-102, requirements to cover open-bodies trucks transporting materials at all times when in motion, pave roadways and maintain them in clean

- condition, and promptly clean paved streets, pursuant to LAC 33:1305.A.4, A.6 and A.7;
- For FUG-103, a requirement to install dust enclosures, pursuant to LAC 33:III.1305.A.3;
 - For DOC-101, an opacity requirement, pursuant to LAC 33:III.1311.C (Specific Requirement #4 incorporates a production-based mass emission limit, but the opacity standard in LAC 33:III.1311.C is a separate standard);
 - For DRI-101/201, production based emission limits and opacity limits, pursuant to LAC 33:III.1311.B and 1311.C;
 - For DRI-102/202, production based emission limits and opacity limits, pursuant to LAC 33 :III.1311.B and 1311.C;
 - For DRI-103/203, production based emission limits and opacity limits, pursuant to LAC 33:III.1311.B and 1311.C;
 - For DRI-104/204, requirements to apply asphalt, oil, water, or suitable chemicals on materials stockpiles, and other surfaces which can give rise to airborne dusts; to install and use dust collectors to enclose and vent the handling of dusty materials; and to provide adequate containment methods, pursuant to LAC 33:1305.A.2 and A.3;
 - For DRI-105/205, production based emission limits and opacity limits, pursuant to LAC 33:III.1311.B and 1311.C;
 - For DRI-106/206, production based emission limits and opacity limits, pursuant to LAC 33:III.1311.B and 1311.C;
 - For DRI-107/207, production based emission limits and opacity limits, pursuant to LAC 33:III.1311.B and 1311.C;
 - For DRI-108/208, production based emission limits and opacity limits, pursuant to LAC 33 :III.1311.B, 1311.C, and 1313.C;
 - For DRI-112/212, production based emission limits and opacity limits, pursuant to LAC 33:III.1311.B and 1311.C;
 - For DRI-115/215 and DRI-116/216, requirements to apply asphalt, oil, water, or suitable chemicals on materials stockpiles, and other surfaces which can give rise to airborne dusts; to install and use dust collectors to enclose and vent the handling of dusty materials; and to provide adequate containment methods, pursuant to LAC 33:1305.A.2 and A.3; and production based emission limits and opacity limits, pursuant to LAC 33:III.1311.B and 1311.C;
 - For DRI-117, production based emission limits and opacity limits, pursuant to LAC 33:III.1311.B and 1311.C;
 - For DRI-118, production based emission limits and opacity limits, pursuant to LAC 33:III.1311.B and 1311.C
 - For each of these sources, in addition to the SIP emission limitations, the Part 70 permit should include monitoring and recordkeeping requirements sufficient to assure compliance with the SIP emission limitations.

LDEQ Response to Comment No. VII.86

LAC 33:III.Chapter 13 requirements were added to the Title V permit. In addition, a requirement was added to the Title V and PSD permits directing Nucor to comply with the *NSLA Dust Management Plan* dated June 2009. This plan will be attached to the permit.

Comment No. VII.87

The DRI manufacturing plant will be a major source of n-Hexane and therefore the Part 70 permit must -- but does not -- incorporate a case-by-case MACT determination for emissions of a-Hexane. A new major source of a hazardous air pollutant ("HAPs") must control emissions of the hazardous air pollutant using maximum achievable control

technology ("MACT"). 42 D.S.C. § 7412(g). A source is "major" if it emits greater than 10 tons/yr of a single HAP or 25 tons/yr of combined HAPs. 42 D.S.C. § 7412(a)(1). If EPA has not promulgated a categorical MACT standard applicable to the new source, a case-by-case MACT determination must be made by the permitting agency. *Id.* The DRI process will emit 11.1 ton/yr of n-Hexane, a listed HAP, and therefore is a major source of HAPs. n-Hexane is also a Class III toxic air pollutant ("TAP") listed in the Louisiana Comprehensive Toxic Air Pollutant Emission Control Program, so the DRI process is also a major source of TAPs. See LAC 33:III.5103.A. State MACT is not required for Class III TAPs. See LAC 33:III.5109.A.1. This state- only exemption, however, does not excuse the DRI process from compliance with CAA § 112. The DRI Part 70 permit must include a case-by-case MACT determination of n- Hexane emissions from the DRI process, and specific requirements necessary to assure continuous compliance with the case-by-case MACT determination.

LDEQ Response to Comment No. VII.87

The DRI plants use natural gas as a fuel and as a raw material to generate reducing gas. Neither the original "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters" (i.e., 40 CFR 63 Subpart DDDDD), promulgated by EPA on September 13, 2004,¹⁴³ nor EPA's proposed "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters"¹⁴⁴ establish emission limits for natural-fired boilers and process heaters. According to the later document:

[W]e [EPA] believe that proposing emission standards for new gas-fired boilers and process heaters that result in the need to employ the same emission control system as needed for the other fuel types would have the negative benefit of providing a disincentive for switching to gas as a control technique (and a pollution prevention technique) for boilers and process heaters in the other fuel subcategories. In addition, emission limits on gas-fired boilers and process heaters may have the negative benefit of providing an incentive for a facility to switch from gas (considered a "clean" fuel) to a "dirtier" but cheaper fuel (*i.e.*, coal). It would be inconsistent with the emissions reductions goals of the CAA, and of section 112 in particular, to adopt requirements that would result in an overall increase in HAP emissions.¹⁴⁵

In view of EPA's findings as published in these two rulemakings, the DRI plants will be controlled to MACT standards.

On December 7, 2010, EPA filed a motion requesting that the D.C. Circuit extend the agency's court-ordered deadline to promulgate MACT standards. According to this document, "the public interest will be best served if the Agency's deadline ... is extended from January 16, 2011, to April 13, 2012, so that EPA can re-propose the rules for further public comment to ensure that the final rules are logical outgrowths of the proposals." On January 21, 2011, the court denied this motion and directed EPA to promulgate final rules by February 21, 2011.

Per 40 CFR 63.40(a), the "requirements of §§63.40 through 63.44 of [Subpart B] carry out section 112(g)(2)(B) of the 1990 Amendments." 40 CFR 63.40(b) states:

¹⁴³ 69 FR 55253. Subpart DDDDD was subsequently vacated and remanded to EPA by the U.S. Court of Appeals for the District of Columbia Circuit on June 19, 2007.

¹⁴⁴ 75 FR 32006 (June 4, 2010)

¹⁴⁵ 75 FR 32029

Overall requirements. The requirements of §§63.40 through 63.44 of this subpart apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants after the effective date of section 112(g)(2)(B) (as defined in §63.41) and the effective date of a title V permit program in the State or local jurisdiction in which the major source is (or would be) located **unless the major source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to section 112(d), section 112(h), or section 112(j) and incorporated in another subpart of part 63, or the owner or operator of such major source has received all necessary air quality permits for such construction or reconstruction project before the effective date of section 112(g)(2)(B).**

(Emphasis added.)

Because a federal standard will be in place before operations of the DRI plants commence, the “major source in question has been specifically regulated ... under a standard issued pursuant to section 112(d).” Thus, section 112(g) of the CAA does not apply.

Comment No. VII.88

The DRI manufacturing plant will emit formaldehyde at greater than the minimum emission rate; therefore the Part 70 permit must -- but does not -- incorporate a case-by-case MACT determination for emissions of formaldehyde. As noted in the previous comment, the DRI process is a major source of TAPs. A major source of TAPs that is permitted to emit a Class I or Class II TAP at a rate greater than the minimum emission rate (“MER”) for the TAP must implement case-by-case MACT for that pollutant. LAC 33:III.5109.A. The DRI process will emit 0.46 tons/yr (= 920 pounds/yr) of formaldehyde. The MER for formaldehyde is 260 pounds/yr. Therefore, the DRI Part 70 permit must include a case-by-case MACT determination for formaldehyde emissions. The Statement of Basis states that MACT determinations were made for units “A, B, C, D, and E,” but it does not identify what emission units in the DRI process -- if any -- to which these generic letter designations apply. The Statement of Basis also states that MACT determinations are cited as LAC 33:III.5109.A in the permit -- but the permit doesn't cite any specific requirement to § 5109.A. The Statement of Basis should be clarified. And, in addition to revising the Part 70 permit to include specific requirements necessary to assure continuous compliance with the case-by-case MACT determination, including without limitation requirements to report emissions, develop standard operating procedures, and conduct emission tests and continuous monitoring. LAC 33:III.5107.A, 5109.C, and 5113.

LDEQ Response to Comment No. VII.88

Emissions of formaldehyde are generated through combustion of natural gas at the package boilers, and combustion of natural gas mixed with spent reducing gas at the reformers. Natural gas is a *Group 1 virgin fossil fuel* as that term is defined at LAC 33:III.5103.A, and are exempt from the control requirements of LAC 33:III.Chapter 51. The natural gas mixed with spent reducing gas and combusted at the reformers meets the exemption criteria of LAC 33:III.5105.B.3.c, and is also exempt from control under Chapter 51.

Comment No. VII.89

The modifications to the pig iron process will cause a significant increase in naphthalene

emissions. According to the Statement of Basis for the modified pig iron Part 70 permit, emissions of naphthalene will increase by 1.95 tons/yr as a result of the modifications to the pig iron process. Naphthalene is a Class II TAP with a MER of 1,990 pounds/yr (= 1.0 ton/yr). As noted in a previous comment, the DRI process is a major source of TAPs. A major source of TAPs that is permitted to emit a Class I or Class II TAP at a rate greater than the minimum emission rate ("MER") for the TAP must implement case-by-case MACT for that pollutant. LAC 33:III.5109.A. Therefore, the modified pig iron Part 70 permit must include a case-by-case MACT determination for naphthalene emissions. The Briefing Sheet does not reflect any MACT determination for naphthalene emissions. A case-by-case state MACT determination must be made and specific requirements necessary to assure continuous compliance with the MACT standard must be incorporated in the modified pig iron Part 70 permit, including without limitation requirements to report emissions, develop standard operating procedures, and conduct emission tests and continuous monitoring. LAC 33:III.5107.A, 5109.C, and 5113.

LDEQ Response to Comment No. VII.89

The permit modification will not increase permitted emissions of naphthalene. In fact, permitted emissions of naphthalene (and methylnaphthalenes) will decrease by 0.01 TPY due to elimination of the coke battery HRSG bypass vents.

In the "Emission Rates for TAP/HAP & Other Pollutants" section of Permit No. 2560-00281-V0, annual emission limits were established for naphthalene and "naphthalene (and methyl naphthalenes)." However, the Air Permit Briefing Sheet of Permit No. 2560-00281-V0 reflected only total naphthalene emissions.

The compounds regulated as toxic air pollutants (TAPs) under LAC 33:III.Chapter 51 include naphthalene (CAS No. 91-20-3), methylnaphthalene (CAS No. 1321-94-4), 1-methylnaphthalene (CAS No. 90-12-0), and 2-methylnaphthalene (CAS No. 91-57-6) and are collectively referred to as "naphthalene (and methylnaphthalenes)" in Tables 51.1 and 51.2 of LAC 33:III.5112. Because Permit No. 2560-00281-V1 correctly represents the regulated TAP as naphthalene (and methylnaphthalenes), "Before" emissions should be listed as 2.47 TPY. Permit No. 2560-00281-V1 will be revised accordingly.

Comment No. VII.90

Nucor should be required to provide an ambient air quality analysis for sulfuric acid mist ("SAM") emissions. LAC 33:III.5109.B requires an ambient air quality analysis for any TAP emitted above the MER. Unlike the MACT requirement in LAC 33:III.5109.A, the ambient air quality analysis requirement is not limited to Class I and Class II TAPs. SAM is a Class III TAP with an MER of 75 pounds/yr. As discussed in the comments above regarding SAM emissions from DRI and pig iron emission units that will be controlled by SCR, the conversion of SO₂ to SO₃ by the SCR catalyst will generate SAM emissions. Specifically, the addition of SCR to control NO_x emissions will cause over 400 tons/yr of SAM emissions – over 10,000 times higher than the MER. Nucor should be required to perform an ambient air quality analysis for SAM emissions and demonstrate that the impact of Sam will not exceed the Louisiana Ambient Air Standard.

LDEQ Response to Comment No. VII.90

This comment is substantially the same as a portion of Comment Nos. VII.38 and 39. Please see LDEQ Response to Comment Nos. VII.38 and 39 for our response to this comment.

Comment No. VII.91

Nucor must obtain a PSD permit to construct SCR for sources in the pig iron process. As discussed in Comment #39, installation of SCR on pig iron sources will cause SAM emissions to increase by greater than 7 tons/yr, and therefore this project will cause a significant increase in SAM emissions. See LAC 33:III.509.B. Nucor must obtain a new PSD permit in order to commence construction of the modified pig iron process. See LAC 33:III.509.A.3. In addition to BACT determinations, PSD requires Nucor to provide, among other things, an ambient air quality analysis for the modified pig iron process and an opportunity for public review and comment on the BACT determinations and air quality impact analysis. As discussed in Comment # 1, this air quality analysis must reflect the aggregate emissions from the DRI-pig iron facility. The public comment period provided for the modified pig iron Part 70 permit does not suffice because it did not include BACT or an air quality analysis for pig iron sources, and did not provide the procedural protections provided under PSD.

LDEQ Response to Comment No. VII.91

This comment is substantially the same as a portion of Comment Nos. VII. 38 and VII. 39. Please see LDEQ Response to Comment Nos. VII. 38 and VII. 39 for our response to this comment.

Comment No. VII.92

The ambient air quality analysis for the 1-hour NO₂ NAAQS and PSD increment may not take credit for eliminating the HRSG bypass vent emissions or installing SCR on pig iron sources. According to Nucor, it is proposing to eliminate the HRSG bypass vents on the coke ovens and install SCR on several pig iron sources solely to satisfy EPA's request to model the aggregate NO_x emissions from the DRI and pig iron processes. Nucor's modeling shows that NO_x emissions just from the pig iron process as permitted under Permit No. PSD-LA-740 -- with HRSG bypass vents and no SCR -- will cause a violation of the 1-hour NO₂ NAAQS. (As explained in Comment #43, our modeling shows that the aggregate NO_x emissions will cause a violation of the 1-hour NO₂ NAAQS even taking credit for these modifications). Nucor's attempt to use a Part 70 permit "modification" for this purpose is inappropriate and falls short of the requirements under the Clean Air Act and SIP.

Air quality modeling for NAAQS compliance must be based on a source's potential emissions. "Potential to emit" is defined as:

the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is *federally enforceable*.

40 C.F.R. § 51.165(a)(iii); LAC 33:III.509.B (emphasis added). To be federally enforceable, a physical or operational limitation must meet two criteria: "(1) the limitation must be contained in a permit that itself is federally enforceable ... and (2) the limitation must be enforceable as a practical matter." See John B. Rasnic, Applicability of Policy on Limiting Potential to Emit to General Motors Morrain Assembly Plant, Dayton Ohio, Sept. 2, 1992, p. 3; Kathie A. Stein, Guidance on Enforceability Requirements for

Limiting Potential to Emit through SIP and § 112 Rules and General Permits ("Stein"), Jan. 25, 1995, p. 5. Controls must be "'unquestionably' and 'demonstrably' effective in order to be taken into account." *Ogden Projects, Inc. v. New Morgan Landfill Co.*, 911 F. Supp. 863,875 (B.D. Pa. 1996) (quoting *National Mining Ass'n v. USEPA*, 59 F.3d 1351, 1364 (D.C. Cir. 1995); Stein, p. 8 (limitations must be "technically sufficient to provide assurance to EPA and the public that they actually represent a limitation on the potential to emit for the category of sources identified," and must require specific compliance monitoring).

Physical or operational limitations that do not meet these criteria are not federally enforceable. Blanket emission limits -- not accompanied by federally enforceable physical or operating restrictions -- may not be considered in the determination of a source's potential to emit. *United States v. Louisiana-Pacific Corp.*, 682 F. Supp. 1141, 1160 (D. Colo. 1988); Terrell E. Hunt, Guidance on Limiting Potential to Emit in New Source Permitting, Jun. 13, 1989, p. 3. In addition, "controls that are only chimeras and do not really restrain an operator from emitting pollution," or which will be "knowingly and regularly violated" also do not limit the source's potential to emit. *National Mining Association*, 59 F.3d at 1361; *Ogden Projects*, 911 F. Supp. at 876; *Louisiana-Pacific*, 682 F. Supp. at 1161.

All these criteria for unenforceable controls describe the pig iron Part 70 permit modifications. The emission rates that Nucor used in its modeling are reflected in the criteria pollutants inventory table, but that is the only place they are reflected. The Specific Requirements reflect BACT emission limitations from the initial pig iron PSD permit, without SCR. See, e.g., Specific Condition #237 (BACT for coke oven FGD stack is "Nitrogen dioxide ≤ 0.71 lb/ton of coal charged"), 265, 343 (BACT for sinter plant MEROS stack is "Nitrogen dioxide ≤ 0.495 lb/ton of finished sinter"). There are no Specific Conditions in the modified pig iron Part 70 permit that directly require installation of SCR or monitoring of any operational parameter specific to SCR. Moreover, Nucor insists that SCR is technically infeasible for the blast furnace, coke ovens, sinter plant MEROS stack, and top gas boilers, see EDMS Doc. 7731641, pp. 228-229, 247, 289, 301, and economically infeasible for control of NO_x from the slag mill dryer. *Id.*, p. 278-79. In other words, Nucor knows that SCR will not work for the pig iron sources and the modified pig iron Part 70 permit does not require Nucor to actually install or operate SCR, but Nucor wants to get credit for the control that SCR would provide. SCR is a chimera, and the blanket emission limits in the criteria pollutant table are not federally enforceable.

The elimination of HRSG bypass vents from the criteria pollutant table -- and air quality impact modeling -- is even more egregious. The modified pig iron permit simply ignores these sources. They are not in the criteria pollutant table, but there is no Specific Condition that requires Nucor to physically eliminate the bypass vents. Nucor's letter addendum to the pig iron modification application -- the only place Nucor discusses the elimination of emissions from the HRSG bypass vents -- provides absolutely no indication of how Nucor plans to eliminate them. In fact, when Zen-Noh commented in April 2010 that Nucor should consider installing spare HRSG units so as to eliminate the bypass vents, LDEQ responded that this cannot be done. There is nothing in the record now that is technically sufficient to provide assurance to EPA and the public that the HRSG bypass vent emissions actually will be eliminated. Like the pig iron SCR, the elimination of HRSG bypass vent emissions is a chimera, and the blanket emission limit of zero emissions from these sources is not federally enforceable.

Therefore, the potential emissions for NO₂ air quality impact modeling must assume that

SCR is not installed and that the HRSG bypass vents emit the same amounts reflected in the initial pig iron Part 70 permit.

LDEQ Response to Comment No. VII.92

The air quality modeling associated with the pig iron and DRI permits is, in fact, based on each operation's potential to emit. Regarding the feasibility of SCR controls, see LDEQ Response to Comment No. V.B.4. LDEQ's BACT determinations associated with PSD-LA-740 have not been modified; however, the commenter's statement that the requirement to install SCR controls is "unenforceable" is not accurate. First, the NO_x limitations established by Permit No. 2560-00281-V1 are federally enforceable. See, for example, LDEQ Response to Comment No. V.C.6. Second, in order to eliminate any ambiguity regarding this matter, LDEQ will add Specific Requirements to Permit No. 2560-00281-V1 explicitly requiring SCR controls to be installed.

LDEQ has not "ignored" the coke battery HRSG bypass vents; Permit No. 2560-00281-V1 eliminates them. Nucor has proposed to install a spare HRSG to eliminate the bypass vents (COK-105 – COK-109 and COK-205 – COK-209), and these sources have been removed from the permit. "Physical or operating restrictions" are therefore not necessary. Any emissions resulting from the bypass of a HRSG would be a violation of the permit for which EPA or LDEQ could take enforcement action.

Comment No. VII.93

Emission rates in the DRI Specific Conditions and Part 70 permit are unsupported. Emission rates are summarized in the draft table, "Emissions Rates for Criteria Pollutants." The maximum hourly emissions rates from this table were modeled in the source impact analyses, required under the PSD regulations, which are applicable requirements. The relationship between these emission rates and the BACT determination are unknown. There is no evidence that these emission rates were derived from a top-down BACT analysis, nor that they correspond to the maximum degree of reduction that is achievable. The assumptions on which they are based appear with no supporting documentation.

The DRI Application and addenda do not include any technical basis, such as design parameters, engineering drawings and calculations, vendor guarantees, citations to literature, stack tests, emission factor compilations such as AP-42, mass balances, engineering calculations, or other indicators that the emissions fairly represent those that will be released from the facility equipped with BACT controls. The permits should be revised to require that the bases of the emission calculations be included as enforceable limits in the permit. The bases of emission calculations that are unsupported include the following:

- For DRI-101/201 (Iron Oxide Day Bins Dust Collection): design volumetric vent rate, gas dust loading, PM10 mass fraction, and PM2.5 mass fraction are unsupported.
- For DRI-102/202 (Iron Oxide Screen Dust Collection): design volumetric vent rate, gas dust loading, PM10 mass fraction, and PM2.5 mass fraction are unsupported.
- For DRI-103/203 (Coating Bin Filter): design volumetric vent rate, gas dust loading, PM10 mass fraction, and PM2.5 mass fraction are unsupported.
- For DRI-104/204: wind erosion chemical suppression, water spray control efficiency, material silt content, percentage of PM10 in material, heavy equipment control efficiency (70%), and moisture content are not supported.
- For DRI-105 (Furnace Feed Conveyor Baghouse): design volumetric vent rate, gas dust loading, PM10 mass fraction, and PM2.5 mass fraction are unsupported.

- For DRI-106/206 (Upper Seal Gas Vent): volumetric vent rate, seal gas system off-take, PM emission factors, uncontrolled NO_x concentration, PM₁₀ filterable mass fraction, PM_{2.5} filterable mass fraction, CO emission factor, and SO₂ concentration are unsupported. These sources, described in the DRI Application and included in the emission calculations and draft PSD Permit, are missing from the draft Title V Permit.
- For DRI-107/207 (Furnace Dust Collection): volumetric vent rates, nominal and maximum cleaned gas particulate concentration, nominal/maximum cleaned gas particulate concentration, seal gas system off-take, seal gas total and filterable PM emission factors, uncontrolled NO_x concentration, CO emission factor, SO₂ concentration, and PM₁₀/PM_{2.5} mass fractions are unsupported.
- For DRI-108/208 (Reformer/Main Flue Gas Stack): volumetric vent rates, seal gas system off-take, nominal natural gas supplement rate, total and filterable PM emission factors, uncontrolled NO_x concentration, PM₁₀/PM_{2.5} mass fractions, CO emission factor, SO₂ emission factor, water vapor concentration, SCR control efficiency, and average/maximum ammonia slip are unsupported.
- For DRI-109/209 (Package Boiler Flue Stack): flue gas flow rate, PM emission factor, NO_x emission factor, SO₂ emission factor, CO emission factor, SCR control efficiency, and average/maximum ammonia slip are unsupported.
- DRI-110/210 (Hot Flare): average/maximum top gas to flare, SO₂ emission factor are unsupported.
- DRI-111/211 (Acid Gas Absorption Vent): venting rate, particulate concentration, CO concentration, and SO₂ concentration are unsupported. These sources, described in the DRI Application and included in the emission calculations and the draft PSD Permit, are missing from the draft Title V Permit.
- DRI-112/212 (Product Storage Silo Dust Collection): volumetric vent rate, nominal/maximum cleaned gas particulate concentration, reformer volumetric vent rate, seal gas system off-take, seal gas total/filterable PM emission factor, uncontrolled NO_x concentration, CO emission factor, SO₂ concentration, and PM₁₀/PM_{2.5} mass fraction are unsupported.
- DRI-113/114 (Process Water Cooling Towers): percent drift and TDS concentration are unsupported.
- DRI-115 (Product Screen Dust Collection): volumetric vent rate, nominal/maximum cleaned gas particulate concentration, and PM₁₀/PM_{2.5} mass fraction are unsupported.
- DRI-116 (Screened Product Transfer Dust Collection): volumetric vent rate, nominal/maximum cleaned gas particulate concentration, and PM₁₀/PM_{2.5} mass fraction are unsupported.
- DRI-117 (Briquetting Mill): fines ratio, volumetric vent rate, maximum vent rate ratio, cleaned gas dust loading, and PM₁₀/PM_{2.5} mass fraction are unsupported.
- DRI-119 (DRI Barge Loading Dock): loading collection and control efficiency and material moisture content are unsupported.

LDEQ Response to Comment No. VII.93

The applicant presented the emissions calculations as based upon vendor-supplied test data and guarantees. The facility must comply with the emissions limits contained within the permit, or present to LDEQ a new air quality impact analysis demonstrating that the allowable emissions increase would not cause or contribute to air pollution in violation of any national ambient air quality standard.

Comment No. VII.94

Emission rates in the DRI Permits are not practicably enforceable. The DRI PSD permit contains no monitoring at all, instead incorporating monitoring in the DRI Part 70 permit into the PSD permit by reference. The underlying PSD permit must comply with the PSD regulations at LAC 33:111.509, as it is the statutory basis of the Part 70 applicable requirement. The DRI Part 70 permit does not contain sufficient monitoring to assure continuous compliance with applicable requirements because the monitoring is largely based on unsupported indicator monitoring, the limitations lack averaging times, and the direct monitoring is infrequent

In many cases, the Part 70 permit requires monitoring of various indicator parameters such as pressures, flow rates, visible emissions, moisture content, presence of a flame, etc. instead of emissions of the regulated pollutants. This indicator or parametric monitoring does not allow Nucor to show that it is continuously complying with emission limits expressed in average pounds per hour ("lb/hr"), maximum lb/hr, tons per year ("ton/yr"), pounds per million British thermal units ("lb/MMBtu"), grains per dry standard cubic feet ("gr/dscf"), etc. of each pollutant. Further, the rationale for selecting the monitoring requirements in the draft permits is not documented in the permit record. The permit record does not explain how monitoring of any of these indicators is sufficient to ensure continuous compliance with permit limits included in the Part 70 permit. This indicator monitoring is frequently combined with one stack test over the life of the facility and rarely, an annual stack test. A single stack test, or even an annual stack test, is inadequate to demonstrate continuous compliance in the absence of adequate indicator monitoring. *See In the Matter of Tesoro Refining and Marketing Co" Martinez, California Facility*, Petition No. IX-2004-6, p. 9-10 ("Regarding source tests, EPA believes that an annual testing requirement is inadequate in the absence of additional parametric monitoring because proper operation and maintenance of the ESPs is necessary in order to achieve compliance with the emission limit."). The EPA has objected to many Title V permits based on failure to document the rationale for selected monitoring and for failing to establish a correlation between a monitoring parameter and compliance with an applicable emission limit. *See, e.g.,* 40 CFR 70.7(a)(5) and U.S. EPA Region 4 Objection, Proposed Part 70 Operating Permit, Southdown, Inc - Brooksville Plant, Hernando County, Florida, Permit No. 0530010-002-AV, Objections 4 and 7; *In the Matter of Fort James Camas Mill, Order Denying in Part and Granting in Part Petition for Objection to Permit*, December 22, 2000 ("the rationale for the selected monitoring method must be clear and documented in the permit record."); *In the Matter of Waste Management of LA LLC Woodside Sanitary Landfill & Recycling Center*, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition No. VI- 2009-01, May 27, 2010, p. 5; *In the Matter of Public Service Company of Colorado, dba cel Energy, Hayden Station*, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition No. VIII-2009-01, p. 6 ("we find that CDPHE has not established that either indicator is currently adequate to assure proper operation and maintenance of the PM control device in order to assure compliance with the PM limit."), p. 8 ("the selected monitoring requirements must be clear and documented in the permit record."); *In the Matter of Wisconsin Public Service Corporation's JP Pulliam Power Plant*, Order Granting Petition for Objection to Permit, Petition Number V-2009-01, p. 10 ("WDNR must establish the correlation between the operating parameters being measured and the ESP performance, and must identify the parameter indicator ranges in the title V permit if they are to be used to demonstrate compliance."); *In the Matter of Alliant Energy - WP L Edgewater Generating Station, Order Granting in Part and Denying in Part Petition/or Objection to Permit*, Petition Number V-2009-02, p. 8 (... WDNR must establish the correlation between the operating parameters being measured and the ESP performance, and must identify the parameter indicator ranges in the title V permit if they are to be used to demonstrate compliance ... "). Specific examples are

identified in comments below for each emissions source.

The DRI Part 70 permit contains emission rates for five criteria pollutants and 30 toxic air pollutants ("TAPs") and/or hazardous air pollutants ("HAPs") that are emitted from 36 sources. These are incorporated into the Part 70 permit in General Condition III, The maximum hourly emission rates are the basis of the criteria pollutant, TAP, and HAP air quality modeling, which are required under Louisiana's State Implementation Plan and thus are applicable requirements. The Part 70 permit must contain sufficient monitoring to assure compliance with the applicable requirements. 40 C.F.R. § 70.6(c)(1); *see also* 40 C.F.R. § 70.6(a)(3)(i). The rationale for the selected monitoring requirements must be clear and documented in the permit record. *See* 40 C.F.R. § 70.7(a)(5). The monitoring in the DRI Part 70 permit is inadequate for most all sources and pollutants. There is most commonly no monitoring at all, or just a single stack test over the life of the facility. The permit record does not explain how no monitoring, a single stack test over the life of the facility, or even an annual stack test provides adequate monitoring to assure continuous compliance with applicable requirements. In fact, the monitoring never identifies the applicable requirement it satisfies, leaving the reviewer to guess what is intended. Specific examples are identified the comments below.

Monitoring must incorporate both a quantitative element and a temporal element. The temporal element is expressed as an averaging time, and the monitoring must correspond to the averaging period of the limit. The averaging time must be included in an enforceable permit as the stringency of a limit is a function of both the magnitude and averaging time. *See* NSR Manual, pp. pages B.56 and c.4. A long averaging time, such as a 30-day rolling average, allows a source 30 days of operation to average out short-term peaks and thus is much less stringent than an instantaneous limit. Most applicable requirements in the draft permits are not accompanied by an averaging time. Thus, these limits are instantaneous and monitoring must be sufficient to show that the emission units are emitting below the limits at all times. *See* EPA's Review of Proposed Title V Permit No. 0530010-002-AV, Southdown, Inc. - Brooksville Plant, Hernando County, Florida, June 19, 2000, Objection 3; EPA's Review of Proposed Title V Permits for Florida Power & Light, December 11, 1997, Enclosure 1, p. 3 ("In instances where the SIP regulations do not indicate an averaging time for the standard, the permit must include one to determine compliance with the applicable requirement."); *In the Matter of Wisconsin Public Service Corporation's JP Pulliam Power Plant*, Petition Number V- 2009-01, June 21, 2010, Claim III, pp. 8-9. As we demonstrate below, this requirement is never met as the monitoring for all of the subject source is inadequate.

LDEQ Response to Comment No. VII.94

LDEQ has required performance tests of sources subject to a technology-based BACT determination. These tests are then supported by adequate parametric monitoring to assure compliance with the permitted limits, using parameter ranges determined to demonstrate compliance by the test. The use of parametric monitoring techniques is commonplace in environmental permits issued in Louisiana, and throughout the United States. Assertions to the contrary are wholly without merit. Performance testing is conducted to determine compliance with the maximum one-hour emission limitation listed in the permit; as such the averaging time for this determination is one hour. Performance testing must be conducted at the process conditions which would be expected to generate the maximum emissions, which is not necessarily at the highest processing capacity for any given source. This method of testing one-hour intervals at the maximum physical capacity of the emitting equipment assures compliance with the BACT limitations stated in the PSD and Title V permits. Longer averaging times are appropriate for determining compliance with the longer annual average emissions limitation, and may be required

in certain instances.

The specified testing requirements are appropriate to ensure compliance with the permit limits during the five year term of the permit. The validity of these test data will be considered at the review process of the permit renewal.

Comment No. VII.95

The Dust Control Plan should be selected -- and required -- as an element of BACT for fugitive dust sources. Some of the sources at the DRI facility do not emit from stacks or vents but rather from various areas or volumes, such as roads and storage piles, e.g., FUG-103, DOC-101, DRI-104, and DRI-118. BACT for these types of sources consists of various management practices, such as watering, chemical suppression, enclosures, paying, etc. Nucor has developed a Dust Management Plan to assure that BACT is met and ambient standards are protected. However, these management practices are not federally enforceable and thus do not satisfy PSD requirements as the Plan is not required by the permits except for source FUG-102, paved road fugitive dust. The Dust Control Plan should have been identified as one of the control options in the BACT analyses and adopted as BACT for all fugitive dust sources. Thus, it should be listed as an applicable requirement for DRI 101/201, DRI-102/202, DRI-105/205, DRI-103/203, DRI-104/204, DRI-117, DRI-118, DRI-107/207, DRI-115/16, and DRI-112.

LDEQ Response to Comment No. VII.95

To mitigate emissions from Unpaved Road Fugitive Dust (FUG-101) (ARE 0002) and Paved Road Fugitive Dust (FUG-102) (ARE 0003), Nucor must water roadways, periodically sweep paved roads, limit the speed of vehicles on such roads, and take all reasonable precautions to prevent particulate matter from becoming airborne. These precautions shall include, but not be limited to, those specified in LAC 33:III.1305.A.1-7 and the June 2009 or most currently- approved Nucor Steel Louisiana Dust Management Plan.¹⁴⁶ Compliance with the Dust Management Plan is a requirement of both the Title V and PSD permits.

Direct measurement of emissions from paved and unpaved roads is not technically feasible. According to the definition of “Best Available Control Technology (BACT),” if “the administrative authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of *best available control technology*.”¹⁴⁷

The NSR Manual restates this aspect of the definition as follows:

In addition, if the reviewing authority determines that there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant to the maximum extent.¹⁴⁸

Comment No. VII.96

¹⁴⁶ EDMS Document ID 42019193, pp. 268 - 300 (Appendix J)

¹⁴⁷ LAC 33:III.509.B

¹⁴⁸ NSR Manual (pg. B.2)

Operational limitations should be incorporated into the DRI Part 70 permit. The emission calculations are based on a wide array of operational assumptions, such as operating time and throughputs of various pieces of equipment. These operational limits are generally summarized in the "Inventories." However, the Inventories are not part of the enforceable conditions of the Part 70 permit. They, for example, are not incorporated into the Specific Requirements, nor identified in the General Conditions as part of the Part 70 permit. As this table summarizes the assumptions used to calculate the emission rates that are the basis of BACT determinations and that were used to demonstrate compliance with ambient standards in the source impact analyses (LAC 33:III.509.K), they must be made federally enforceable. Thus, the Inventories table should be incorporated into the Part 70 permit and monitoring, recordkeeping and reporting required for each.

LDEQ Response to Comment No. VII.96

LDEQ does not require operational limitations except in cases where the applicant requests an enforceable limit in order to maintain permitted increases beneath certain thresholds (such as PSD applicability), or where an emissions cap across multiple sources is requested for operational flexibility (as is frequently seen in storage tank farms). LDEQ has authority to require and enforce emissions limits, and does not typically require operational limits where they are not requested by the applicant, or warranted by some special situation. It is incumbent upon the applicant to certify compliance with the limitations of the permit, including emission limits.

Comment No. VII.97

Emissions of PM₁₀/PM_{2.5} from DRI-118 are underestimated. The emission calculations for DRI barge loading (DRI-118) underestimate PM₁₀/PM_{2.5} emissions because the moisture content was overestimated, the wind speed was underestimated, and the conveyor service factor was omitted from the calculations.

First, the emission calculations are based on a material moisture content of 0.5%, cited to AP-42 Table 13.2.4-1. This table does not support 0.5%. Among the materials in this table, pellets from taconite processing are the most similar to DRI. Taconite is an iron ore and taconite processing occurs in a furnace and thus would generate a dry product similar to DRI. The range of moisture contents for pellets from taconite mining and processing is 0.05% to 2.2%. The moisture content of the processed taconite pellets and DRI is near zero because they are generated in furnaces at elevated temperatures, which evaporates the moisture. The product DRI must be kept dry and away from oxygen to prevent undesired reactions. The emission calculations, in fact, report the moisture contents of pig iron, a very similar material, as 0.00%. The moisture content of DRI would be similar. However, it is unlikely that the moisture content of DRI would be exactly zero at the point of loading as it will pick up small amounts of moisture during conveyor transport and loading. Thus, we selected the lower end of the moisture content range for pellets from taconite mining and processing or 0.05% as a reasonable estimate for DRI.

Second, the DRI loading emission calculations are based on an average wind speed of 2.0 miles per hour ("mi/hr"). However, all other fugitive emission calculations in which wind speed is a variable use an average wind speed of 7.6 mi/hr, based on the New Orleans Regional Airport Station. There is no justification for using a much lower wind speed in the identical equation for DRI-118 as compared with other fugitive sources, *e.g.*, DOC-101. The effect of this lower wind speed is to underestimate PM₁₀/PM_{2.5} emissions.

Third, other calculations that used the same identical equation included a conveyor

service factor of 115% in calculating maximum hourly emissions to account for maximum operating conditions, *e.g.*, DOC-101, FUG-103. No conveyor service factor was included in the DRI-118 calculations, underestimating PM₁₀/PM_{2.5} emissions.

Making these three corrections to Nucor's calculations, the maximum hourly PM₁₀ emissions increase from the modeled value of 0.78lb/hr to 128 lb/hr and the maximum hourly PM_{2.5} emissions increase from the modeled value of 0.12 lb/hr to 19.4 lb/hr. See Exhibit 1. Nucor should be required to submit a revised air quality impact analysis using the corrected potential emissions from DRI-118.

LDEQ Response to Comment No. VII.97

The commenter has provided no basis for the statement that the moisture content presented by the applicant is unreasonable, and in fact proceeds to cite data that supports the moisture content provided, to wit: "Taconite is an iron ore and taconite processing occurs in a furnace and thus would generate a dry product similar to DRI. The range of moisture contents for pellets from taconite mining and processing is 0.05% - 2.2%." LDEQ agreed with the assumption that the DRI pellets would contain a moisture content of 0.5% because this content is in line with similar materials, and due to the chemistry of the DRI process, in which hydrogen combines with the oxygen of the iron ore, to form water. The commenter's assertion that this moisture is completely removed from the pores of the DRI product is made without support.

DRI loading operations will be conducted inside an enclosed structure due to the product's special handling considerations. LDEQ's assessment is that the wind speed presented by the applicant is reasonable due to the nature of the enclosed space.

The calculations presented in other permit applications are not relevant for the DRI facility. However, these factors were presented as a safety factor to account for running the primary inbound material conveyors near to maximum for extended periods of time. The applicant must comply with the emission rates listed in the permit, which are calculated on the rate of transfer provided in the application emission calculations.

Comment No. VII.98

Emissions of PM₁₀/PM_{2.5} from the cooling towers (DRI-113/114, DRI-213/214) are underestimated. The emission calculations implementing the BACT analysis go a step further than addressed in the draft permits by assuming that only 14.9% of the drift, calculated from the TDS content, drift rate, and circulating water flow rate, is PM₁₀ and PM_{2.5}. There is nothing in the draft permits that restricts PM₁₀ and PM_{2.5} emissions from the cooling towers to only 14.9% of the drift (which is calculated from the circulating water rate, TDS, drift efficiency) nor any way to test for this fraction. The standard method for calculating cooling tower PM₁₀ emissions assumes that 100% of the drift is PM₁₀. In fact, actual measurements using cascade impactors conclusively demonstrate that cooling tower drift is 100% PM₁₀. See G. Israelson, N. Stich, and T. Weast, Comparison of Cooling Tower Mineral Mass Emissions by Isokinetic EPA Method 13A and Heated Cascade Impactor Tests, Cooling Tower Institute Paper No. TP91-12, 1991 and Thomas E. Weast and Nicholas M. Stich, Reduction of Cooling Tower PM₁₀ Emissions Due to Drift Eliminator Modifications at a Chemical Refining Plant, Cooling Tower Institute Paper No. TP92-10, 1992. The researchers conducting these measurements concluded: "there is sufficient information from the first set of cascade impactor tests to support the conclusion that the drift emitted from the cooling towers consists of water droplets that are so small that when they dry, the remaining solid particulates are all PM₁₀." Thus, the cooling tower emissions that were used in the air

quality analysis are underestimated and, consequently, impacts on air quality are underestimated. When this correction is made, $PM_{10}/PM_{2.5}$ emissions from the cooling towers increase from 0.11 lb/hr to 0.74 lb/hr. Nucor should be required to submit a revised air quality impact analysis using the correct emission rates for the water towers.

LDEQ Response to Comment No. VII.98

LDEQ reviewed the basis document provided by the applicant, *Calculating Realistic PM_{10} Emissions from Cooling Towers*, Greystone Environmental Consultants, Inc., 2002, and found the basis for particle size distribution calculations from the cooling towers to be reasonable and acceptable.

Comment No. VII.99

The DRI PSD permit does not include enough stack testing for the package boilers to assure continuous emission reductions. The PSD regulations, which are incorporated into Louisiana's SIP and thus are applicable requirements, require source impact analyses. LAC 33:III.509.K. These analyses require the owner to demonstrate that allowable emission increases would not cause or contribute to air pollution in violation of any national ambient air quality standard or any applicable maximum allowable increase over baseline. Thus, the emission rates included in these analyses are applicable requirements. These analyses include modeling to demonstrate compliance with the 1- hour nitrogen dioxide (" NO_2 ") standard. See, e.g., In re Northern Michigan University Ripley Heating Plant, PSD Appeal No. 08-02 (EAB, 2/18/09). This modeling relied on the maximum hourly NO_x emission rates for the package boilers included in the Criteria Pollutant Emission table. The permit record failed to explain how one stack test over the life of the facility assures compliance with the NO_x BACT limit and the emission rates included in the source impact analyses.

LDEQ Response to Comment No. VII.99

The performance test must be conducted at a minimum of 80% of the rated capacity of the unit, in order to determine compliance with the maximum emission rate listed in the permit, as stated explicitly in the specific requirement. Failure to pass the performance would result in the imposition of operational limits to maintain the permitted maximum emission rate, or the presentation of a new air quality impact analysis demonstrating that the allowable emissions increase would not cause or contribute to air pollution in violation of any national ambient air quality standard.

The specified testing requirements are appropriate to ensure compliance with the permit limits during the five year term of the permit. The validity of these test data will be considered at the review process of the permit renewal.

Comment No. VII.100

Nucor should be required to model the impact of ammonia slip as $PM_{10}/PM_{2.5}$. Nucor's emission calculations indicate that the SCR that would be used to control NO_x emissions from the package boilers (DRI-109/209) and reformers DRI-108/208) is designed to have an average ammonia slip of 10 parts per million on dry basis ("ppmvd") and a maximum ammonia slip of 15 ppmvd. Ammonia is injected into the flue gas to react with NO_x and convert it to nitrogen gas and water. The leftover ammonia that does not react, slips through the catalyst and is emitted into the atmosphere. The proposed ammonia slip is very high for an SCR on a natural gas boiler, which is typically limited to an average of 5

ppmvd. Ammonia is a PM_{2.5} precursor, is converted into PM_{2.5} in the atmosphere, and contributes to condensable PM₁₀/PM_{2.5} at the stack. Thus, this contribution, amounting to a maximum of 2.55 lb/hr from the package boilers and 6.30 lb/hr from the reformers, should have been included in the PM₁₀/PM_{2.5} modeling. The permit record contains no evidence that ammonia slip from the package boilers or other SCR equipped sources was included in the modeled PM₁₀/PM_{2.5} emissions or considered in the PM₁₀ or PM_{2.5} BACT analyses.

LDEQ Response to Comment No. VII.100

USEPA has issued guidance contrary to the commenter's claim, stating that "due to the considerable uncertainty related to ammonia as a precursor, our final rules do not require ammonia to be regulated as a PM_{2.5} precursor." (73 FR 28330)

Ammonia slip is not required to be included in the PM modeling demonstrations. As recently as October 20, 2010, in EPA's PM_{2.5} Final Rule¹⁴⁹, EPA stated, "The impacts of PM_{2.5} precursors on ambient concentrations of PM_{2.5} cannot be determined from the dispersion models that EPA has currently approved for modeling individual PSD sources. Such models are not designed to consider chemical transformations that occur in the atmosphere after the precursor emissions have been released from the source."

Based upon conversations with EPA, at this time the secondary formation of PM_{2.5} is most effectively accounted for in the selection of background monitor. The Bayou Plaquemine monitor was determined to be representative of the rural, agricultural area where the Nucor site will be located. Also, as the Bayou Plaquemine monitor is located downwind of the proposed Nucor site, LDEQ determined that using this monitor will account for secondary formation and transport of PM_{2.5}. EPA Region 6 concurred with this assessment via a January 12, 2010 e-mail from Erik Snyder.¹⁵⁰

Comment No. VII.101

SO₂ emission rates for combustion of natural gas are unrealistically low. The emission rates for the package boilers (DRI -109/209) reported in the "Emission Rate for Criteria Pollutants" table of the DRI Part 70 permit are based on a natural gas sulfur content of 87 gr/MMscf, 1423 times lower than the BACT limit specified by LDEQ. We are not aware of natural gas that has such low sulfur levels, unless specially treated with very expensive sulfur removal methods, which are not proposed here. The lower limit of sulfur in pipeline quality natural gas is typically 2,000 gr/MMscf, the level specified by LDEQ as BACT. Thus, the SO₂ emissions that were modeled from the package boilers are not achievable in practice and are 23 times lower than they will be in practice. This is problematic as the draft permits do not require any monitoring of either sulfur in the natural gas or SO₂ in the exhaust gases from the package boilers. The permits should be revised to include such monitoring. In addition, Nucor should be required to clarify the natural gas sulfur content and submit a revised air quality impact analysis using the correct SO₂ emission rate for these sources.

LDEQ Response to Comment No. VII.101

The commenter is in error in stating that "the lower limit of sulfur in pipeline quality natural gas is typically 2,000 gr/MMscf." This is the upper limit of what LDEQ considers acceptable for sweet

¹⁴⁹ 75 FR 64864

¹⁵⁰ EDMS Document ID 47463793

natural gas, and emission limits based on much lower concentrations of sulfur are frequently permitted by LDEQ. In our experience, the sulfur content of natural gas provided by the applicant is in the range of typical concentrations.

Nucor must demonstrate compliance with this limitation.

Comment No. VII.102

SO₂ emission rates in the Emission Rates for Criteria Pollutants table for DRI sources are not practicably enforceable. First, none of them include an averaging time. An inspector, for example, could not determine whether the ton/yr limit is met if it is only calculated once a year. Second, the DRI Part 70 permit requires only two stack tests over the life of the facility. The permit record contains no evidence that two stacks tests over the life of the facility are adequate to assure continuous compliance with these emission rates. A SO₂ CEMS is generally required to demonstrate compliance with 1 hour emission rates and is feasible for this source.

LDEQ Response to Comment No. VII.102

General Condition III of LAC 33:III.537 states - "The Emission Rates for Criteria Pollutants, Emission Rates for TAP/HAP and Other Pollutants, and Specific Requirements sections of the permit establish the emission limitations and are a part of the permit. Any operating limitations are noted in the Specific Requirements of the permit," thus, making SO₂ limitations practicably enforceable. Also, the commenter's suggestion that "two stack tests over the life of the facility" is inadequate simply ignores the fact that Title V permits must be renewed at five year intervals and ongoing performance testing requirements are a feature of these renewals. LDEQ has determined that the installation of a Continuous Emissions Monitor is not warranted in this instance.

Most of the SO₂ emissions are from the combustion of natural gas. All sulfur content in natural gas will be combusted to form sulfur dioxide. Nucor must annually certify sulfur dioxide emissions based on the quantity of natural gas combusted and the actual sulfur content in natural gas as specified in the natural gas delivery contract.

Comment No. VII.103

PM₁₀/PM_{2.5} emissions from gantry cranes (DOC-101) are underestimated. The Gantry Cranes unload raw materials (coal, iron ore, flux) and load product and byproduct (pig iron, slag, coke) to be shipped elsewhere. The DOC-I cranes service both the Pig Iron and DRI facilities. The PM₁₀/PM_{2.5} emissions included in the air quality modeling from loading and unloading at both Docks 1 (DOC-101) and 2 (DOC-102) are substantially underestimated due to the failure to include fugitive emissions from loading pig iron.

The air quality analysis modeled the "maximum emission rate" from among the maximum emission rates for unloading coal, iron ore, and flux and loading pig iron, slag and coke fines. The calculations are shown in Table 2, extracted from the DRI Application, Addendum 2.17. The maximum value occurs for flux unloading because it has the lowest moisture content, 1.2%, compared to other materials.

See Table 2

However, PM₁₀/PM_{2.5} emissions from loading pig iron at DOC-101 and DOC-102 are set equal to zero based on the assumption that "pig iron has no intrinsic silt content, and is assumed to be non-emitting. This is incorrect. The silt content of undisturbed pig iron

pellets is irrelevant. Fugitive dust is created by pellets banging into one another during various material handling operations, such as conveying and drops. The loading of pellets on conveyors and into the holds of ships, for example, would generate large amounts of fugitive dust from interaction among the pellets. Further, the equation used to calculate the emission factors in Table 2 does not include silt content as a variable and the equation's source, AP-42, is clear that there is no significant correlation between silt content and loading emissions in the underlying data.

The real issue here is that the emission factor for loading emissions used in Table 2 is inversely related to the moisture content of the loaded material raised to the 1.4 power. This means that as the moisture content drops, the emissions from loading increase. If Nucor had estimated loading emissions for pig iron using a realistic value for moisture content in its calculations, $PM_{10}/PM_{2.5}$ emissions would have resulted in significant air quality impacts. The AP-42 equation used to calculate loading emissions, from the conveyor to a ship or barge, is as follows:

$$\text{Emission factor (lb/ton)} = k(0.0032)[U/5]^{1.3} / [M/2]^4 \quad (1)$$

The moisture content of pig iron is near zero because it is generated in a furnace at elevated temperatures, which evaporates the moisture. The emission calculations, in fact, report the moisture content of pig iron as 0.00%. However, it is unlikely to be exactly zero at the point of loading as it will pick up small amounts of moisture during transport. The section of AP-42 that Nucor relied on also reports typical moisture content values for various materials. The range of moisture contents for pellets from taconite mining and processing is 0.05% to 2.2%. Taconite is an iron ore and taconite processing which occurs in a furnace would generate a dry product similar to pig iron. Thus, we estimated $PM_{10}/PM_{2.5}$ emissions for pig iron loading using the lower end of the taconite range, a moisture content of 0.05%, corresponding to "processing," but otherwise following Nucor's calculation procedure. Our calculations are documented in Exhibit 1. These calculations show that the maximum PM_{10} emissions occur when pig iron is being loaded, at 64 lb/hr, compared to the modeled emission rate of 1.5 lb/hr. The maximum $PM_{2.5}$ emission rate when pig iron is included is 9.7 lb/hr, compared with 0.23 lb/hr modeled. Nucor should submit a revised air quality impact analysis using the correct $PM_{10}/PM_{2.5}$ emission rates for DOC-101.

LDEQ Response to Comment No. VII. 103

The commenter states that the intrinsic silt content of pig iron is irrelevant and fugitive emissions from pig iron originate from pig iron pellets colliding into one another during material handling operations. The commenter, however, provided no basis for this assumption. Moreover, the pig iron will not be manufactured in the form of pellets, but rather in much larger solids known as pigs, and will not be handled by conveyors but rather transported to the dock by truck. The calculation and underlying assumptions provided by Nucor are unchanged for these operations, and remain acceptable. The commenter's discussion of the characteristics of taconite ore are irrelevant, due to the fact that the applicant has not included emission calculations on the basis of taconite ore, and these materials do not have the same physical properties.

Comment No. VII.104

Zen-Noh incorporates by reference all exhibits and other documents submitted concurrently with these comments and those exhibits and other documents submitted by Zen-Noh on April 19, 2010 and May 3, 2010 regarding Permit Nos. PSD-LA-740 and 2560-00281-V0.

LDEQ Response to Comment No. VII.104

LDEQ acknowledges the commenter's incorporation by reference. However, LDEQ has already responded to Zen-Noh's comments regarding Permit Nos. 2560-00281-V0 and PSD-LA-740.